Energy Policy Review

How Effective Was Denying the Keystone XL Pipeline Presidential Permit in Reducing Green House Gas Emissions from Canadian Oil Sands Crude?

by

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ABSTRACT

The purpose of this paper is to review what effect denying the presidential permit required to allow a border crossing between Canada and the United States (U.S.) for the Keystone XL (KXL) Pipeline had on potential life-cycle greenhouse gas (GHG) emissions from the West Canada Sand Basin (WCSB) crude oil. The focus of the evaluation is on the potential GHG emissions predicted if the KXL Pipeline were constructed and operated versus potential GHG emissions for other transportation routes without the KXL Pipeline. Current and projected WCSB crude oil production rates and exports are also reviewed and compared to rates and projections at the time of the presidential permit review in 2013. By comparing and contrasting the GHG emissions from alternative modes of transportation and reviewing WCSB crude oil production rates and exports, the paper evaluates the intended and unintended consequences of the decision to prevent construction of the KXL Pipeline as it relates to GHG emissions and climate change.

The results of the evaluation determined that pipeline transport produces the least amount of GHG emissions for transporting WCSB crude oil from Canada to the Gulf Coast. However, the difference between GHG emissions of the different modes of transportation is small. Additionally, the WCSB crude oil production rates and exports to the U.S. continued to increase in the near term despite lower costs per barrel of crude oil and the denial of the KXL Pipeline border crossing permit.

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NOMENCLATURE

Symbols

°*F*	Degrees Fahrenheit

Abbreviations

API	American Petroleum Institute
bbl	Barrel
bpd	Barrels per day
BTU	British thermal unit
CAP	Climate action plan
CAPP	Canadian Association of Petroleum Producers
CEPA	Canadian Environmental Protection Act
CFR	Code of Federal Regulations
CME	Chicago mercantile exchange
CO_2e	Carbon dioxide equivalent
CPP	Clean Power Plan
CSS	Cyclic steam stimulation
ECCC	Environment Climate Change Canada
EIS	Environmental impact statement
EO	Executive order
g	Gram
GHG	Greenhouse gas
GHGRP	Greenhouse gas reporting program

GREET	Greenhouse gas, regulated emissions, and energy use transportation model
kg	Kilograms
KXL	Keystone XL
LCA	Life-Cycle Assessment
LTO	Light tight oil
MDEQ	Montanan Department of Environmental Quality
mi.	Mile
MJ	Mega joule
MM bpd	Million barrels per day
$MMTCO_2e$	Million metric tons of carbon dioxide equivalents
NDEQ	Nebraska Department of Environmental Quality
NEB	National Energy Board
NYMEX	New York mercantile exchange
OPGEE	Oil production greenhouse gas emissions estimator
PADD	Petroleum Administration for Defense District
SAGD	Steam assisted gravity drainage
SDPUC	South Dakota Public Utilities Commission
SEIS	Supplemental environmental impact statement
U.S. EIA	United States Energy Information Administration
U.S. EPA	United States Environmental Protection Agency
U.S.	United States
VFF	Venting, flaring, and fugitive emissions
WCS	Western Canada Select

WCSB	Western Canada Sand Basin
WORLD	World Oil Refining, Logistics, and Demand
WTI	West Texas Intermediate
WTR	Well-to-Refinery
WTW	Well-to-Wheels

GLOSSARY

Bitumen	A form of degraded petroleum in a solid or semi-solid state typically associated with a mixture of sand, clay, and water.
CSS	Cyclic steam stimulation is an in-situ bitumen extraction method utilizing a vertical extraction well. The well is alternately used to inject steam to mobilize the bitumen and pump the mobile bitumen to the surface as it collects in the well.
Dilbit	Bitumen diluted to the point that it will meet pipeline specifications for pumping. Typical ratios are 30% diluents to 70% bitumen.
Diluent	Petroleum-based product typically consisting of naphtha or natural gas condensate used to dilute bitumen.
Heavy crude	Crude oil with a density on the American Petroleum Institute scale of 27 or less.
In-situ extraction	A method of extracting crude from oil sands that occurs below grade typically at depths greater than 50 feet below the surface. The two most common methods are steam assisted gravity drainage and cyclic steam stimulations.
Light crude	A density on the American Petroleum Institute scale of 30 or greater.
Medium crude	Crude oil with a density on the American Petroleum Institute scale between 27 and 30.

Mining	Surface excavation crude removal from the oil sands. This process is typically limited to depths of 50 feet below existing ground surface.
Naphtha	Refined or partially refined light distillates.
Railbit	A less dilute version of bitumen than dilbit that is suitable for transport via rail. Typical ratios are 15% diluents and 85% bitumen.
SAGD	Steam assisted gravity drainage is an in-situ crude removal process that uses a pair of stacked horizontal wells to mobilize bitumen to the point it can flow, be collected and pumped to the surface.
Sour crude	Crude oil with a sulphur content greater than 0.5%.
Sweet crude	Crude oil with a sulphur content less than or equal to 0.5%
WCSB	Athabasca, Cold Lake, and Peace River oil sand deposits located in north and east-central Alberta and western Saskatchewan.

Chapter 1 Introduction

1.1 Problem Statement

President Obama denied the Keystone XL Pipeline ("KXL Pipeline" or "Pipeline") presidential permit application in November 2015 [1] based on the United States (U.S.) State Department's recommendation that the Pipeline would not serve the "national interest" [2]. The basis for the State Department's decision was that approving the permit would undermine the U.S.'s global influence on climate change policy and support a "dirty" crude as an energy source, which runs counter to President Obama's Energy Policy, with little to no benefit to energy security, petroleum product pricing, and jobs, as countered by KXL Pipeline supporters such as Mr. Greg Stringham, Vice President of Oil Sands with the Canadian Association of Petroleum Producers (CAPP) [3].

The Pipeline would primarily transport crude oil generated from the Western Canadian Sand Basin (WCSB) or "oil sands" in Alberta, Canada to the Gulf Coast in the U.S. for refining. WCSB crude oil is an extra heavy crude oil that is in a solid state intermixed with the sand under normal conditions. Large amounts of energy are required both to mobilize extra heavy crude oil for extraction, because of its viscosity, and to separate it from sand. The more energy used, the more greenhouse gases (GHGs) are emitted, contributing to global warming. Because of this, the crude oil was labeled "dirty" by detractors and the Obama administration. This contributed to the primary reason—i.e., to prevent climate change—that the Pipeline was determined to not be in the national interest. There has been much research on life-cycle GHG emissions from the WCSB crude oil in comparison with other crude oils refined in the U.S., but did denying the presidential permit for the Pipeline reduce GHG emissions for the WCSB oil sands?

1.2 Purpose and Methodology

The purpose of this paper is: (1) to review the potential GHG emissions for different modes of transporting WCSB crude oil from Canada to the Gulf of Mexico area for refining and (2) to assess what impact the State Department's decision has had on WCSB crude oil production. By comparing the GHG emissions from different transportation scenarios and reviewing WCSB crude oil production and export rates, the paper will evaluate the intended and unintended consequences of the decision to prevent construction of the KXL Pipeline as it relates to GHG emissions and climate change.

Denying TransCanada the needed presidential permit for the KXL Pipeline to cross over the border was intended to serve the national interest by reducing GHG emissions and encouraging other world leaders to take similar steps. Critics of the KXL Pipeline argued that without the cheaper transportation afforded by the Pipeline, crude oil producers would have smaller profit margins, which would reduce or limit well production in the WCSB, especially if the price per barrel of crude fell below the breakeven point of $65-$75/barrel [4]. This would reduce GHG emissions by reducing WCSB crude oil production and keeping crude in the ground [1].

The focus of the evaluation will be on the potential GHG emissions predicted if the KXL Pipeline were constructed and operated versus potential GHG emissions for other transportation routes without the Pipeline. The WCSB production, transportation and projections will also be reviewed to determine if denying the presidential permit had the intended effects. This capstone project report features use of a combination of information gathered from models, studies, and emission factors to calculate GHG emissions.

1.3 Importance

The WCSB is the third largest proven crude reserve in the world, but the maximum capacity of the existing pipelines and railroad loading terminals in the oil sands region is less than the projected production capabilities [5]. The amount of crude oil in the area means the petroleum industry is continuing to search for economical ways to expand the transportation capacity, including constructing the KXL Pipeline or an alternative to transport crude out of this area into the U.S. With the Obama Administration no longer in office in 2017, it is reasonable to expect another pipeline proposal from TransCanada or others in the petroleum industry to cross the Canada-U.S. border from the new administration. In this case, the U.S. State Department would again be evaluating whether transporting WCSB crude across the international border is in the U.S.'s best interest and how it may affect climate change.

Canada does have their own refineries. However, they are primarily located on the east coast and geared for lighter crude oils because that is where Canada's conventional crude oil is located. U.S. refining capabilities currently exceed those of Canada. The U.S. has the infrastructure to refine the projected production capacity of the WCSB and distribute the refined products to end users, and the Gulf Coast refineries, the intended destination of the KXL Pipeline, have the largest capacity in the U.S. [6]. Since the U.S. has the refining capability, is in close proximity, and has a good trading relationship with Canada, it is a desirable export recipient of the WCSB crude.

1.4 Limitations

The presidential permit process and debate over approval of the KXL Pipeline has drawn a lot of attention and controversy. Much research has been done on the best method to calculate GHG emissions for the WCSB crude. This capstone project report is not seeking to reproduce this body of work, but instead utilizes the data and results from many of these studies. Nor does the report review climate change or make any recommendations or conclusions on whether or not this is a valid environmental concern. The report also does not evaluate or describe theoretical climate change impacts that may occur with an increase or decrease in life-cycle GHG emissions from the WCSB crude. This paper was written with the assumption that a global reduction of GHG emissions is a valid goal. Finally, this paper does not review other hazards or environmental impacts associated with the extraction, transportation, refining, or use of WCSB crude (e.g., oil spills, habitat disruption, cultural impacts, environmentally sensitive areas, etc.), but focuses only on GHG emissions.

Chapter 2 Literature Review

The purpose of this report is to review the decision to deny the presidential permit for the KXL Pipeline as it relates to life-cycle GHG emissions generated from the WCSB. In order to understand the impacts and ramifications of this decision, a brief understanding of the petroleum industry, regulations, and other GHG emission research in these two nations is required.

2.1 U.S. and Canada Petroleum Industry and Terminology

This section reviews common terminology used in the petroleum industry and U.S. and Canadian energy sectors.

2.1.1 Crude Oil Reserves

A country's proven crude oil reserve (this paper uses "crude oil" and "crude" interchangeably to mean unrefined petroleum from natural resources and does not include liquid from natural gas production) is a measure of recoverable crude based on geologic conditions, engineering technology and economic situation from a given date forward [1]. In addition to newly discovered crude resources, proven volumes may also increase by technological advancements or economic circumstances that allow more crude oil to be extracted.

2.1.2 Crude Oil Grade and Classification

Each crude reserve is given a name such as the U.S. West Texas Intermediate (WTI) or the WCSB. The crude oil is graded by density or "weight" (light, medium, heavy) and sulfur content (sweet, sour). Sweeter crude oils have a lower sulfur content (typically less than 0.5% sulfur), and sour crude oils have a higher sulfur content (typically up to 4% sulfur). WCSB crude oil is considered extra heavy and sour.

The American Petroleum Institute (API) Gravity (referred to as "degrees API" or just "API") is the standard scale by which the weight of all crude oils are measured [7]. Thus,

$$Degrees\ API = (141.5/specific\ gravity\ at\ 60°F) – 131.5.$$

The API scale is inverse to density so the denser the crude, the lower the degree API. An API of 10 is equal to water so anything greater than 10 will float and less than 10 will sink. Though the exact difference between classifications can be region specific, the general classifications used in the U.S. for the "weight" of crude are:

- Light: API > 38
- Medium: 22 < API > 38
- Heavy: 10 < API > 22
- Extra Heavy: API < 10.0

The classification of a crude directly affects its market value. Lighter, sweeter crudes are priced higher because they are easier to refine and transport. Additionally, higher sulfur contents (“sour” crude) are more corrosive to equipment, require additional measures to curb emissions, and can produce hydrogen sulfide, which is an irritant and chemical asphyxiant that requires additional health and safety monitoring, making sour crudes less desirable and lower in value. In general, lighter crude oils have lower sulfur content and produce fewer GHGs to extract, transport, and refine.

The API gravity of the crude oil deposit determines what method of extraction, transportation, and refining is available. Light, medium, and heavy crude oils that are liquids at standard temperature and pressure and do not require additional stimulation in order for the crude oil to enter a recovery well are considered conventional crude oils. Extra heavy crude oil with a degraded form of petroleum or "bitumen" mixed with sand and clay require non-traditional extraction wells and steam or chemical stimulation to mobilize the crude oil for extraction.

2.1.3 Petroleum Administration for Defense Districts (PADDs)

In 1942, the 50 states were divided into five geographic regions or districts as shown in Figure 1. The districts were originally organized to ration fuel during World War II. They were repurposed when Congress passed the Defense Production Act of 1950 and renamed them Petroleum Administration for Defense Districts (PADDs) [8] . The Defense Production Act of 1950 authorized the President and federal agencies to make provisions for fuel and materials during times of disaster or acts of terrorism. Today the PADDs are used solely for energy statistical analysis in order to track energy resources, movement, refining, and use on a regional basis.

Most of the U.S. petroleum industry statistics and data presented in this report were compiled by the U.S. Energy Information Administration (EIA). The EIA was established in 1974 to provide Congress with annual energy reports in response to the 1970s energy crisis. It is part of the Department of Energy, but works independently to compile data and report on the energy sectors in the U.S. [9].

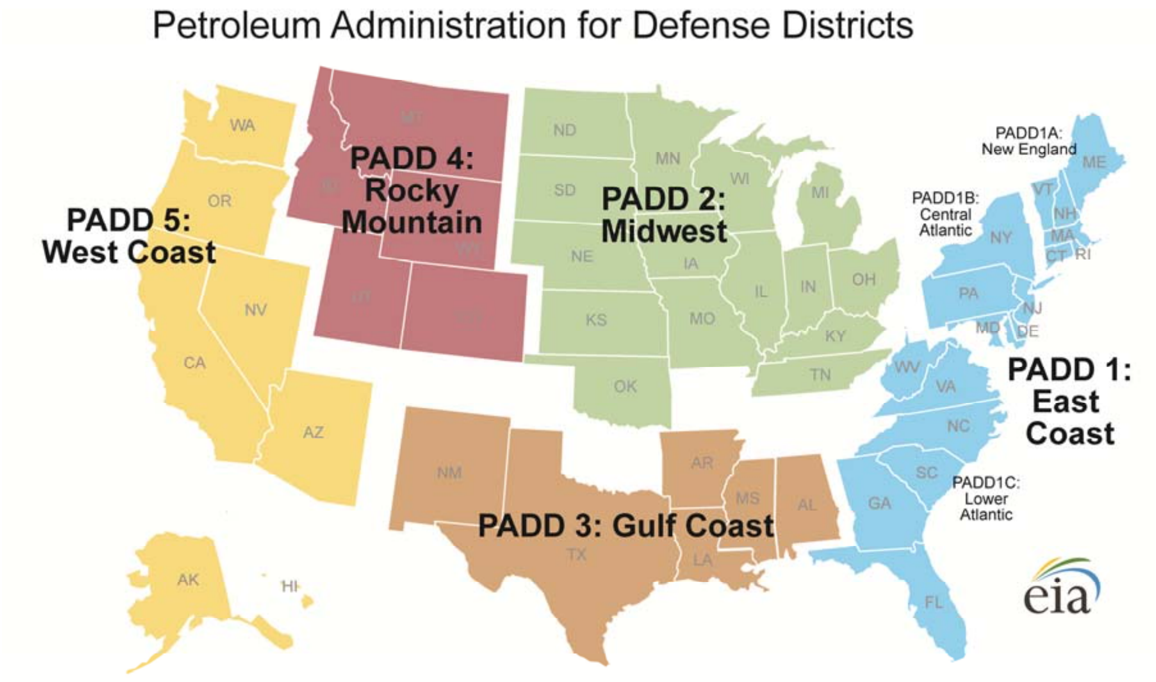


Figure 1: Organization of U.S. into Petroleum Administration for Defense Districts (PADDs) [2].

2.2 Conventional Crude Oil Extraction

Only 50-60% of the crude oil in a deposit is expected to be recoverable before the amount of energy required to extract it exceeds the potential energy in the crude oil. Conventional crude oil wells use a number of methods to remove the crude oil over the life of the well. Vertical recovery wells are drilled into the crude oil formation. The first 5-15% of crude accumulates in the recovery well for removal under natural pressures. The next phase of extraction requires mechanical extraction by injecting fluids to increase pressure and/or pumping the crude to the surface and removes 30-40% of the available crude oil. The final phase of extraction is the addition of heat and/or surfactants and other chemicals to decrease the viscosity of the crude to increase accumulation rates. The final stage typically only removes about 5-15% of the available crude oil [10].

2.2.1 Oil Sands/Bitumen Extraction

A large percentage of the world's crude oil is in the form of oil sands; the two largest oil sands deposits are in Venezuela and Canada. Other places oil sands can be found are the Middle East and U.S. However, Canada has the most developed industry to extract the crude [11].

There are two main types of oil sand extraction—pit mining and in-situ. Pit mining uses excavators and trucks to remove the oil sand to processing facilities that separate the crude from the sand and clay. Mining is limited by depth (typically 50-70 feet below grade). In-situ extraction involves the use of heat and/or steam to increase the mobility of the crude in place so that it can be pumped to the surface. There are two main methods: steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). SAGD uses a pair of horizontal wells stacked one above the other. Steam is injected in the top well to mobilize crude to collect in the bottom well for extraction. CSS uses a vertical well that is alternatively used to inject steam into the formation and remove the mobilized crude after it accumulates in the well [12]. SAGD and CSS are similar to the final stages of extraction from a conventional well, but require longer periods of time and more energy to extract the crude.

2.2.2 Petroleum Liquid Pipeline Network

Pipelines are large diameter pipes either above or below grade that transport crude oil and other petroleum fluids over long distances. Pump stations along the route are used to move the fluid through the pipe. The advantage of pipelines is that they require low maintenance and operation, there is no return trip required, or limits on delivered quantities due to weight restrictions or container sizes. Throughput is measured in barrels per day (bpd). The disadvantage is that the orders are not discrete so there is mixing between deliveries to different locations. There is an existing network of pipelines between Canada and the U.S. Refer to Figure 2 for a figure of the U.S. and Canadian crude oil pipeline network and Table 1 for the pipeline capacities [13].

Pipeline operators have specific standards for viscosity that are required in order for crude oil to be transportable via pipeline. WCSB crude oil in the raw form ("rawbit") does not meet these specifications. In order to transport WCSB crude oil by pipeline, it is diluted with other partially refined light distillates (e.g. naphtha) or natural gas condensate referred to as "diluent". The mixture is called "dilbit" and typically is mixed to a ratio of 30:70 diluent to bitumen [12].

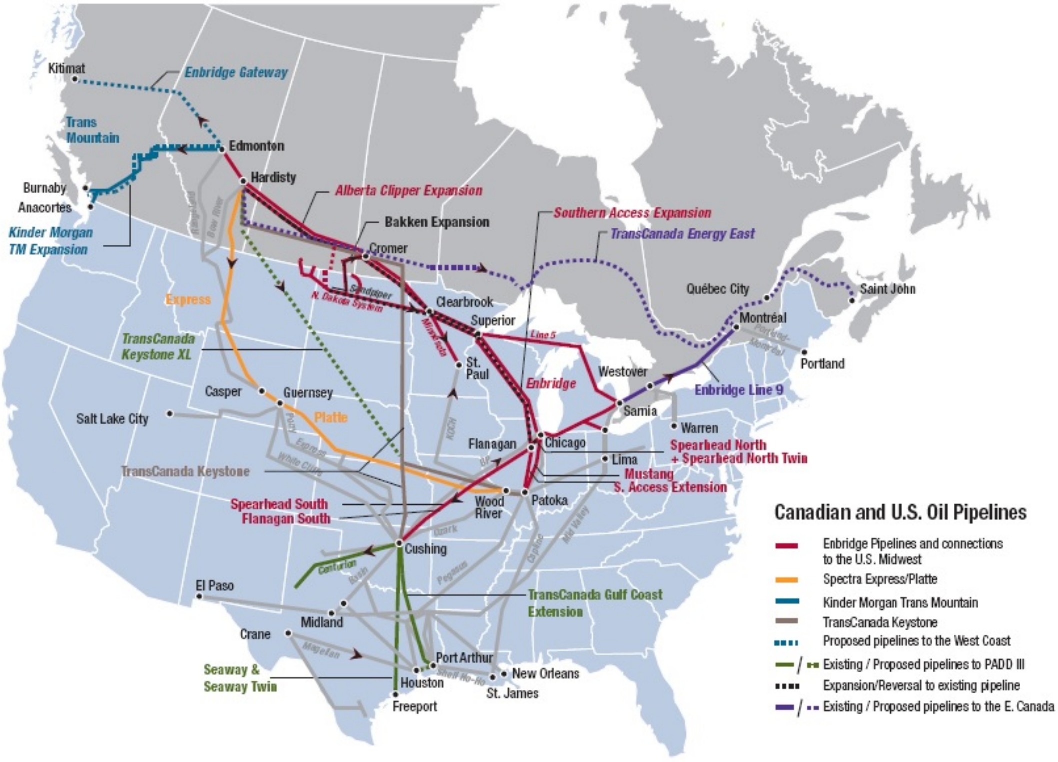
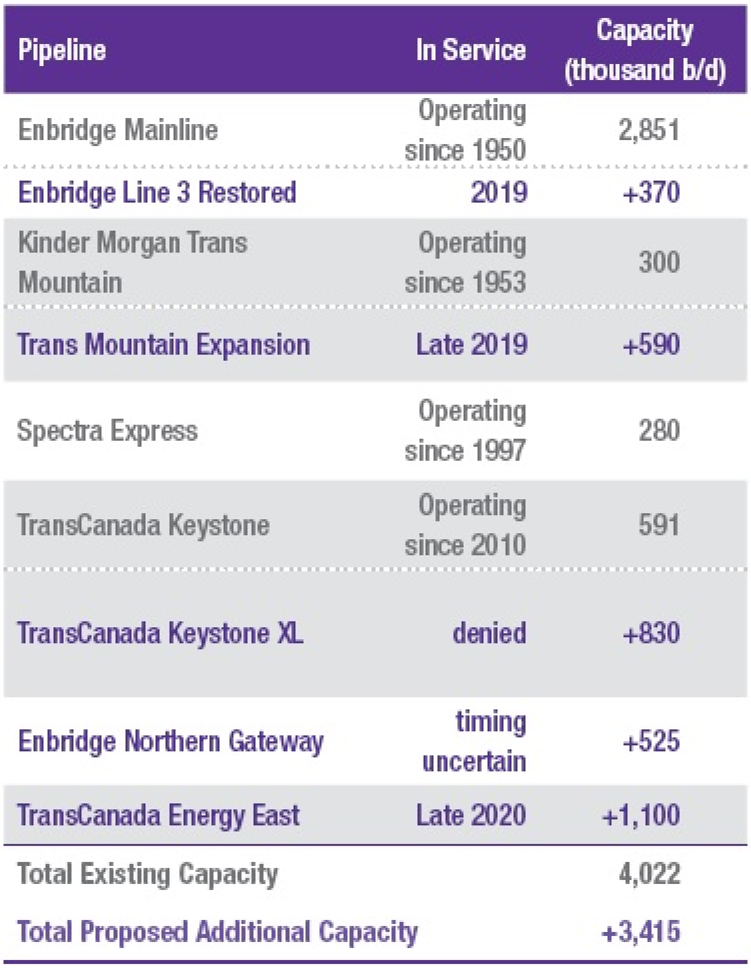


Figure 2: Existing and Proposed Canadian and U.S. Crude Oil Pipelines [13].

Table 1: Major Existing and Proposed Crude Oil Pipelines Transporting Out of the WCSB [13].



Pipeline	In Service	Capacity (thousand b/d)
Enbridge Mainline	Operating since 1950	2,851
Enbridge Line 3 Restored	2019	+370
Kinder Morgan Trans Mountain	Operating since 1953	300
Trans Mountain Expansion	Late 2019	+590
Spectra Express	Operating since 1997	280
TransCanada Keystone	Operating since 2010	591
TransCanada Keystone XL	denied	+830
Enbridge Northern Gateway	timing uncertain	+525
TransCanada Energy East	Late 2020	+1,100
Total Existing Capacity		4,022
Total Proposed Additional Capacity		+3,415

2.2.3 Petroleum Railroad Transportation

Crude oil is also transported to refineries by railcar. Railcars for liquid transfer may be equipped with steam heating coils and insulation for thicker fluids like rawbit that require heat to mobilize for offload. If the rail car is not equipped with heating coils or the refinery destination does not have steam heat equipment at the railcar offload location, the bitumen may need to be diluted prior to rail transport. Otherwise, the diluent is added to the bitumen at a ratio of 15:85 to ensure the crude oil can be offloaded from un-insulated rail cars without the assistance of steam heat at the destination.

Another aspect of rail transport is the use of unit trains versus manifest trains. If all the rail cars on a train are transporting the same product from the same point of origin and destination, it is referred to as a "unit train". Otherwise, if there are multiple products, origins, and destinations, the train is referred to as a "manifest train". Unit trains offer quicker delivery times and cost savings as there are fewer stops and less coordination [12]. Railcar transport has advantages because there is a large network of railroad already in place between Canada and the U.S. Disadvantages to rail transport include return time for empty railcars to be reloaded for the next shipment. According to the CAPP, the typical railroad route from Alberta, Canada to Texas, U.S. is 2,485 miles (mi.) in length and has a round trip of 13.5 - 15 days.

The largest railcar has a gross weight limit of 286,000 pounds and can hold approximately 575 barrels of railbit [12]. The KXL Pipeline had a nameplate capacity of 830,000 bpd [14]. To transport an equivalent amount of crude oil (factoring in diluent ratios) via railcar (assuming the use of unit trains with 120 railcars per train) would require approximately 10 trains or 1,189 railcars per day.

2.2.4 Petroleum Waterborne Transportation

Waterborne crude oil transportation occurs via barge and tanker. Barges are non-powered and towed from one place to the other. Marine tankers are self-propelled. In Canada, crude oil is transferred through pipelines or railcars to the designated port location for loading onto a barge or tanker.

To transport crude oil from Alberta, Canada to the Gulf Coast via barge, the crude oil would travel approximately 1,133 mi. via railcar from Alberta, Canada to a port in St. Paul, Minnesota (U.S.). In Minnesota, the crude oil would be transferred from the railcar onto a barge and travel approximately 2,200 mi. along the Mississippi River to the Gulf of Mexico and ports in Texas. A typical barge has a weight limit of 8.56 MM pounds and can hold approximately 25,150 barrels of railbit [15]. The KXL Pipeline had a nameplate capacity of 830,000 bpd [14]. To transport an equivalent amount of crude oil (factoring in diluent ratios) via railcar and barge would require approximately 1,189 railcars and 28 barges per day.

2.2.5 Petroleum Refining

Refining is the process that turns the raw crude oil into usable products such as gasoline, diesel fuel, heating oil, jet fuel, petrochemical feedstock, waxes, lubricating oils, and asphalt. Refer to Figure 3 for a graphic representation of end products from one barrel of crude oil. All crude oil, regardless of API gravity, produces the same or similar end products but in different quantities. Different classifications of crude oil do require different refining processes and have different levels of GHG emissions. In general, the heavier the crude oil, the more energy and emissions to process.

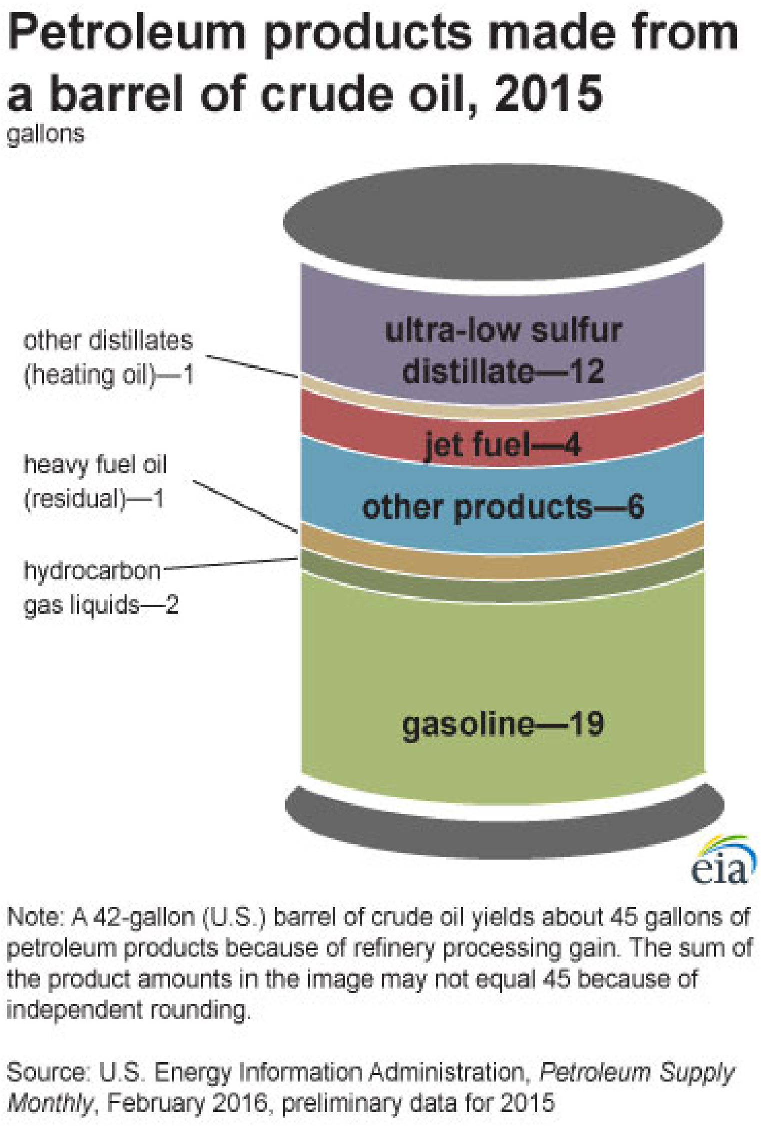


Figure 3: Petroleum Products Made From A Barrel of Crude Oil [16].

2.2.6 Petroleum Market Value

The WTI is a crude oil stream traded on the New York Mercantile Exchange (NYMEX) that is often referenced as a benchmark for the price of crude oil in North America. This paper uses WTI for all crude oil pricing references. There is a Western Canadian Select (WCS) heavy oil stream produced exclusively in Western Canada, beginning in 2003. However, it is traded on the Chicago Mercantile Exchange (CME) as the differential from WTI in what is called the heavy oil discount. The reason WCS price is typically less than the WTI price is due to increased transportation costs out of Alberta, Canada and refining costs [17]. Prior to 2003, WTI was trading at less than $25/barrel. Since 2003, the price per barrel has increased significantly with a peak of $133/barrel in 2007 before seeing a rapid decline to levels below $50/barrel since 2013. Refer to Figure 4 for the monthly WTI price over the past 15 years [18].

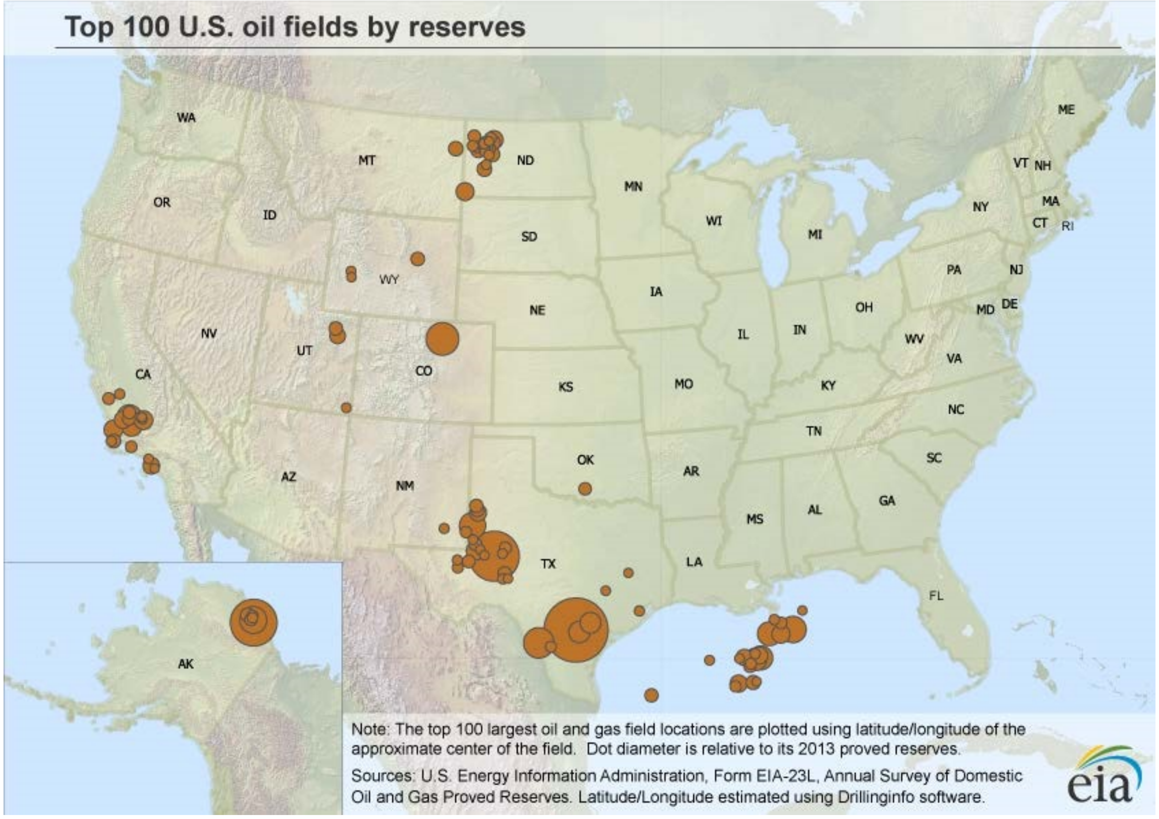
Figure 4: West Texas Institute (WTI) Price per Barrel in U.S. Dollars [18].

2.3 U.S. and Canada Petroleum Supply and Demand

This section explores the current and projected petroleum supply and demand for Canada and the U.S. and the trading relationship between the two countries.

2.3.1 U.S. Crude Oil Reserves

As of 2014, the U.S. has the eleventh largest proven crude reserve in the world with approximately 36.5 billion barrels. This number peaked in the 1970s [5]. Refer to Figure 5 for the location of the largest oil producing areas in the U.S. and Figure 6 for a graph of total proven crude reserves quantity in the U.S. since 1980.



Note: The top 100 largest oil and gas field locations are plotted using latitude/longitude of the approximate center of the field. Dot diameter is relative to its 2013 proved reserves.

Sources: U.S. Energy Information Administration, Form EIA-23L, Annual Survey of Domestic Oil and Gas Proved Reserves. Latitude/Longitude estimated using Drillinginfo software.

Figure 5: Top 100 Largest U.S. Oil Field Locations [19].

In the past decade, the use of hydraulic fracking—a well-stimulation technique that injects water, sand, and other additives at high pressures to fracture the bedrock—has facilitated the ability to recover crude oil previously deemed unrecoverable. The crude, referred to as light tight oil (LTO), is typically a light to medium density crude that was hard to remove because it was located in tight sandstone or shale formations that inhibited crude movement. Hydraulic fracking introduces cracks into the bedrock that allow the crude to accumulate in recovery wells. The ability to access and remove LTO allows it to be included in the U.S. inventory, which is the reason for the slight increase in U.S. crude reserves observed in 2009 in Figure 6.

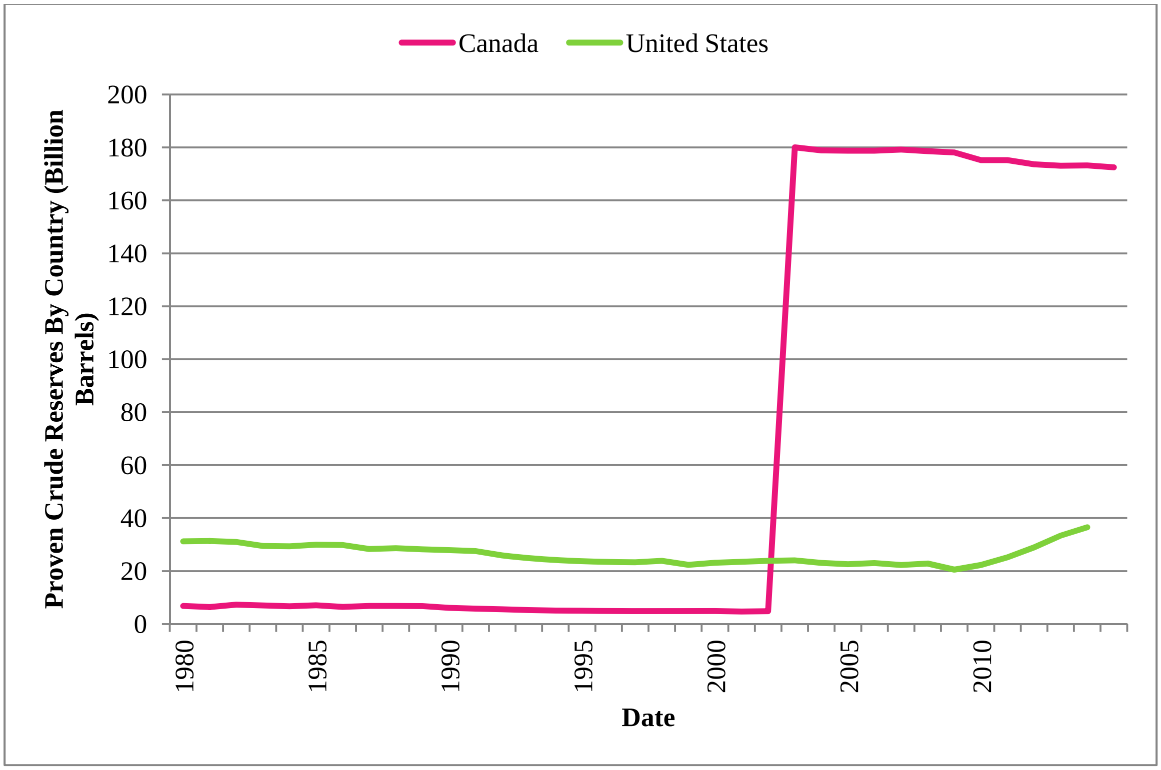


Figure 6: U.S. and Canada Proven Crude Oil Reserves since 1980 [5].

2.3.2 Canada Crude Oil Reserves

As of 2014, Canada has the third largest proven crude oil reserve in the world. They first achieved this status in 2003 when 11% of the oil sands crude was included in their national reserves. Refer to Figure 6 for a graph of proven crude reserves in the U.S. and Canada since 1980. Up until 2003, the oil sands crude oil—primarily located in northeastern Alberta Province—was not considered recoverable because the cost to extract was more than it was worth on the market, and therefore, it was not included in Canada's total oil reserves. The oil sands status change was based on a combination of extraction technology improvements and an increase in the price per barrel of crude, which compensated for the larger capital costs associated with extracting crude from the oil sands [5]. The increase in price per barrel of crude played a significant role in the reason that Canadian oil sands are now considered recoverable.

The main oil sands deposits are in Athabasca, Cold Lake, and Peace River in Alberta and Saskatchewan. Canadian conventional crude produced is considered 29% heavy crude, 54% light and medium crude, and 17% distillates, while bitumen is considered heavy to extra heavy crude. Refer to Figure 7 for the location of the oil sands deposits.

Figure 7: Canadian Oil Sands Region [13].

2.3.3 U.S. Crude Oil Production

Production is the process of removing or extracting crude oil from the ground. In 2015, the top five countries producing (or extracting) crude oil were the U.S., Saudi Arabia, Russia, China, Canada, and Iraq (Figure 8) [20]. U.S. production sharply increased every year of the Obama presidency, partly due to technological advances that improved drilling efficiencies and partly due to a national goal of becoming self reliant for energy needs. In 2015, U.S. crude oil production was 15 million barrels per day (MM bpd), which was the highest U.S. production has been since the 1970s.

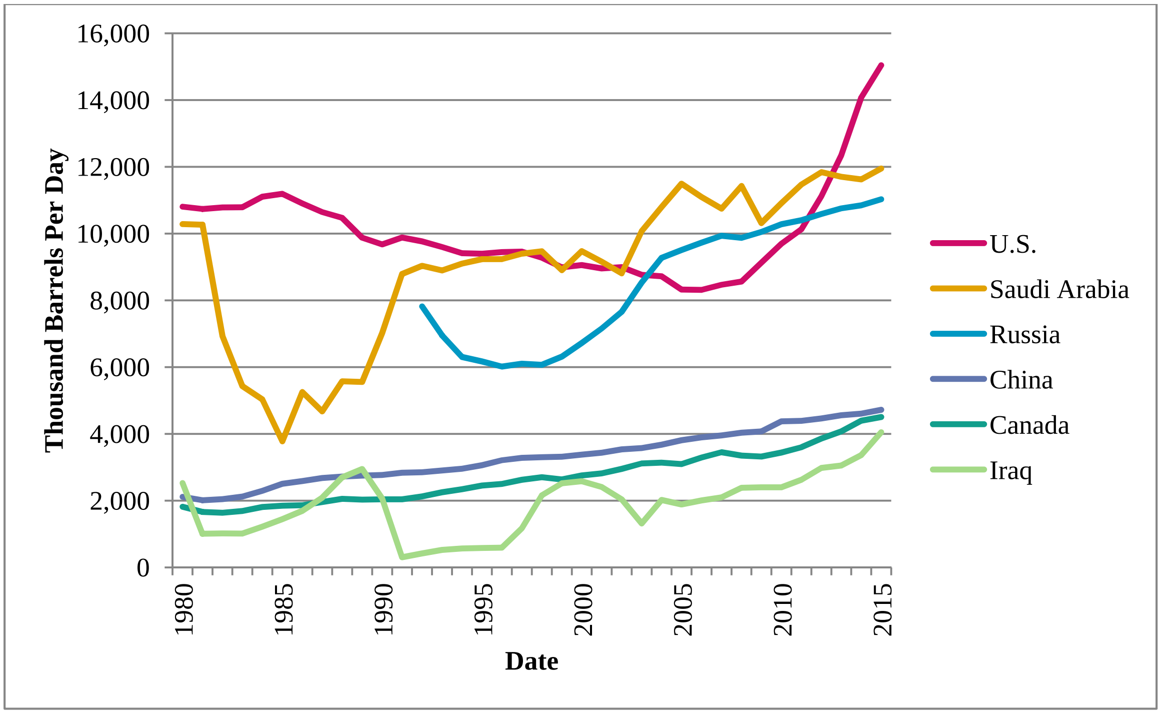


Figure 8: Total Petroleum and Other Liquids Production for Top Six Countries [20].

The U.S. produces mostly light to medium, sweet crude oil, but they do produce a heavy, sour crude in California and other areas. In 2015, the top five domestic crude oil producers were Texas (37%), offshore drilling in Gulf of Mexico (16%), North Dakota (12%), California (6%), and Alaska (5%) [21].

2.3.4 Canada Crude Oil Production

Canadian production (or extraction) has continued to grow each year since 1980 (start of the data set). Canada produces a conventional crude in addition to the extra heavy crude from oil sands or "bitumen". In 2015, Canadian crude oil production was 3.85 MM bpd. Conventional crude made up approximately 39% of the total crude oil produced in Canada at 1.49 MM bpd, with the remaining 2.36 MM bpd from oil sands production [13]. Refer to Figure 9 for a graph of Canadian crude oil production by type.

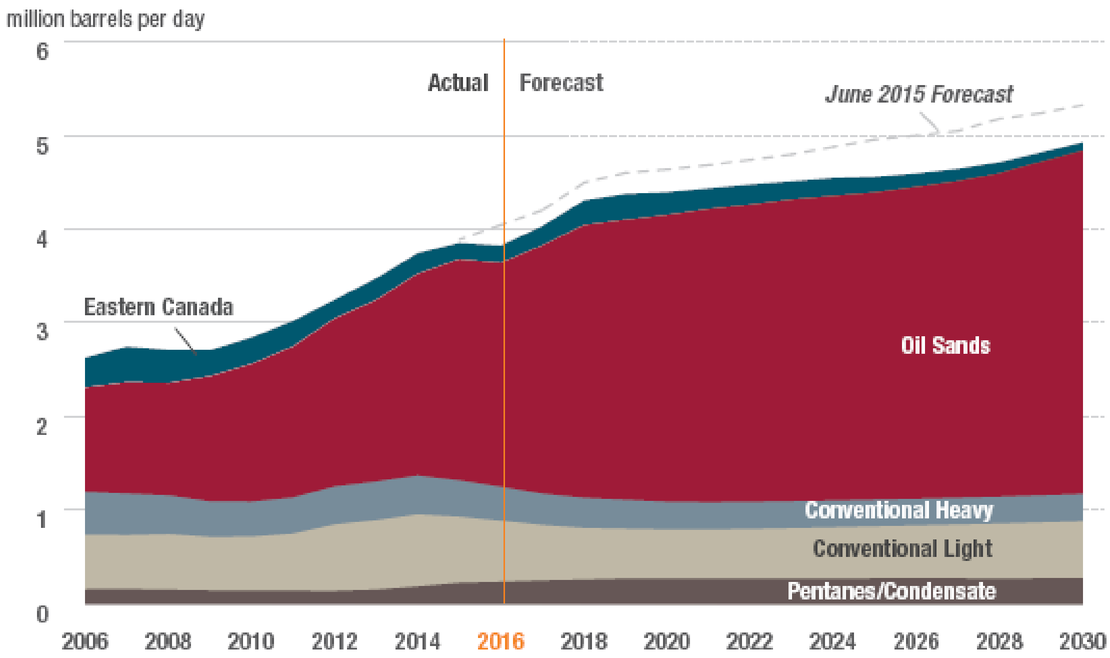
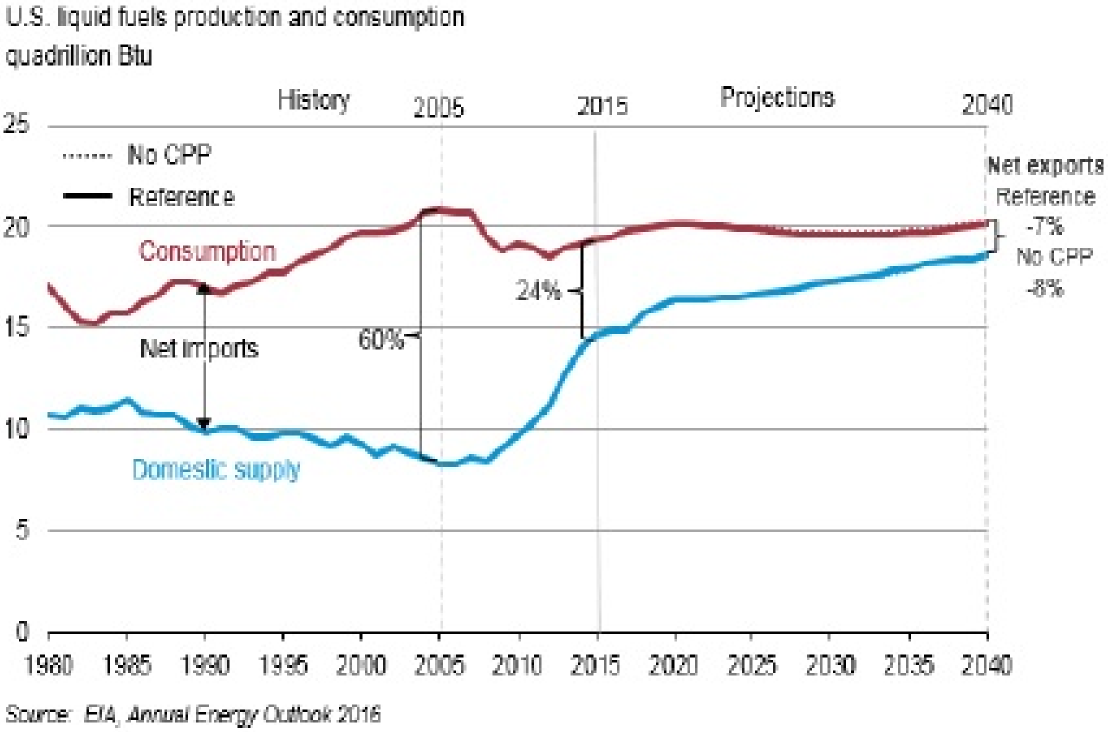


Figure 9: Canadian Crude Oil Production [13].

2.3.5 U.S. and Canada Petroleum Demand

In 2013, the top five petroleum consumers (in order) were U.S., China, Japan, India, and Russia. Canada ranked number nine. At 18.9 MM bpd, the U.S. represents just over 20% of the petroleum consumed in the World. The next largest country (China) accounts for 12% of the World petroleum consumption [22].

As of 2015, the U.S consumes more petroleum than they produce, requiring the country to import crude oil to meet demand. Refer to Figure 10 for a comparison of U.S. liquid fuel consumption versus production since 1980. Conversely, Canadian petroleum consumption was 2.4 MM bpd in 2015 [20]. Compared to 2015 production rates of 3.85 MM bpd [13], Canada has a net surplus of crude oil.



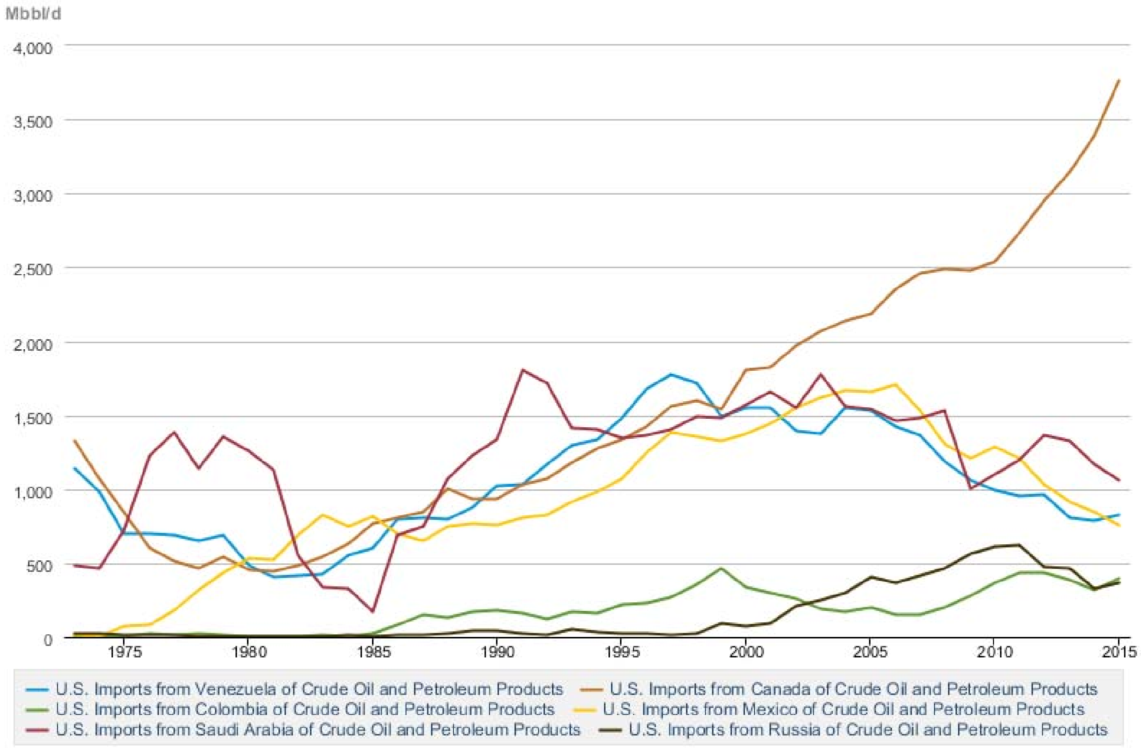
Source: EIA, Annual Energy Outlook 2016

BTU = British thermal units, CPP = Clean Power Plan

Figure 10: U.S. Production versus Consumption [23].

2.3.6 U.S.-Canada Crude Oil Trade

The U.S and Canada have an extensive crude oil trade relationship. The U.S. is the primary recipient of Canadian exports [13]. Canada has been the top crude oil source for the U.S. since 2000 and is the only crude oil source that has increased production every year for the past five years [24]. Refer to Figure 11 for the top U.S. suppliers [24].



Source: U.S. Energy Information Administration

Figure 11: U.S. Crude Oil Imports by Country of Origin [24].

All U.S. PADDs have experienced an increase of Canadian crude oil imports in the past five years, but PADD 2 and PADD 5 have seen the biggest increase in imports since 2012 [25]. This coincides with additional pipelines constructed and expanded in this time frame. Refer to Figure 12 for Canadian crude oil imports by PADD.

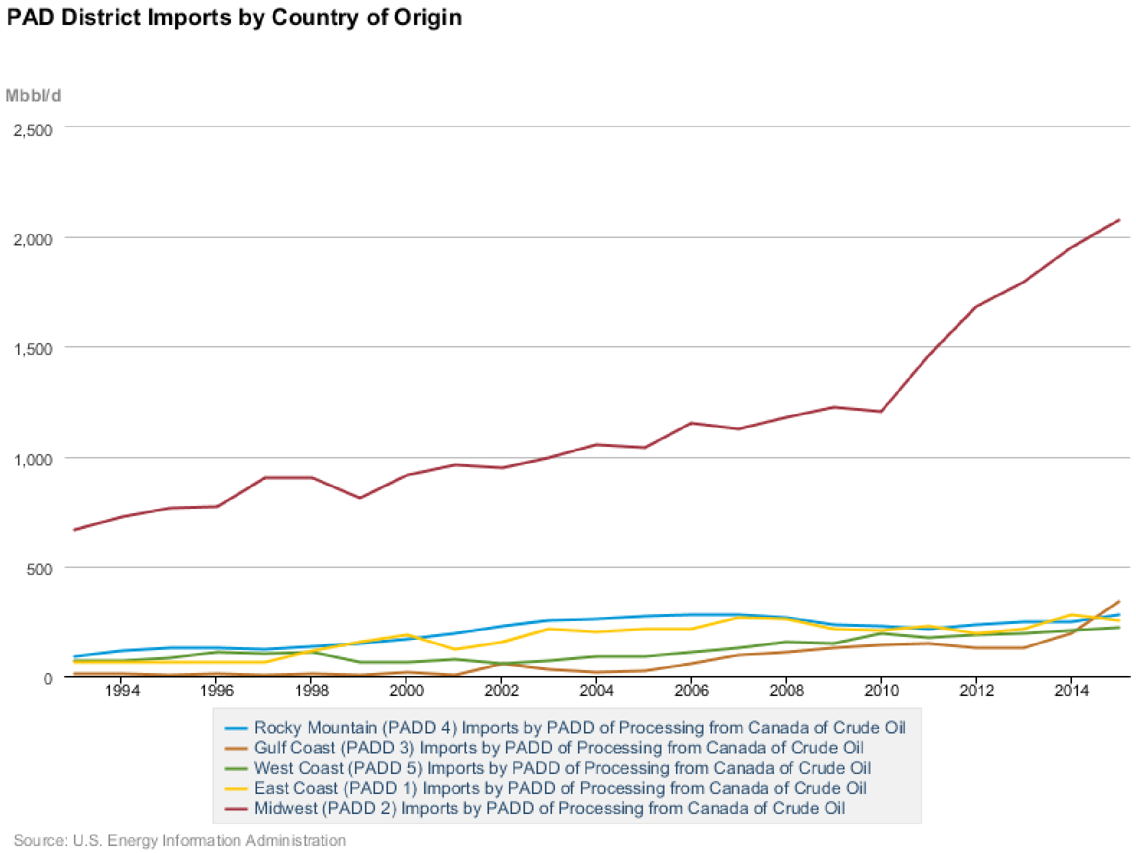


Figure 12: Canadian Crude Oil Imports by PADD [25].

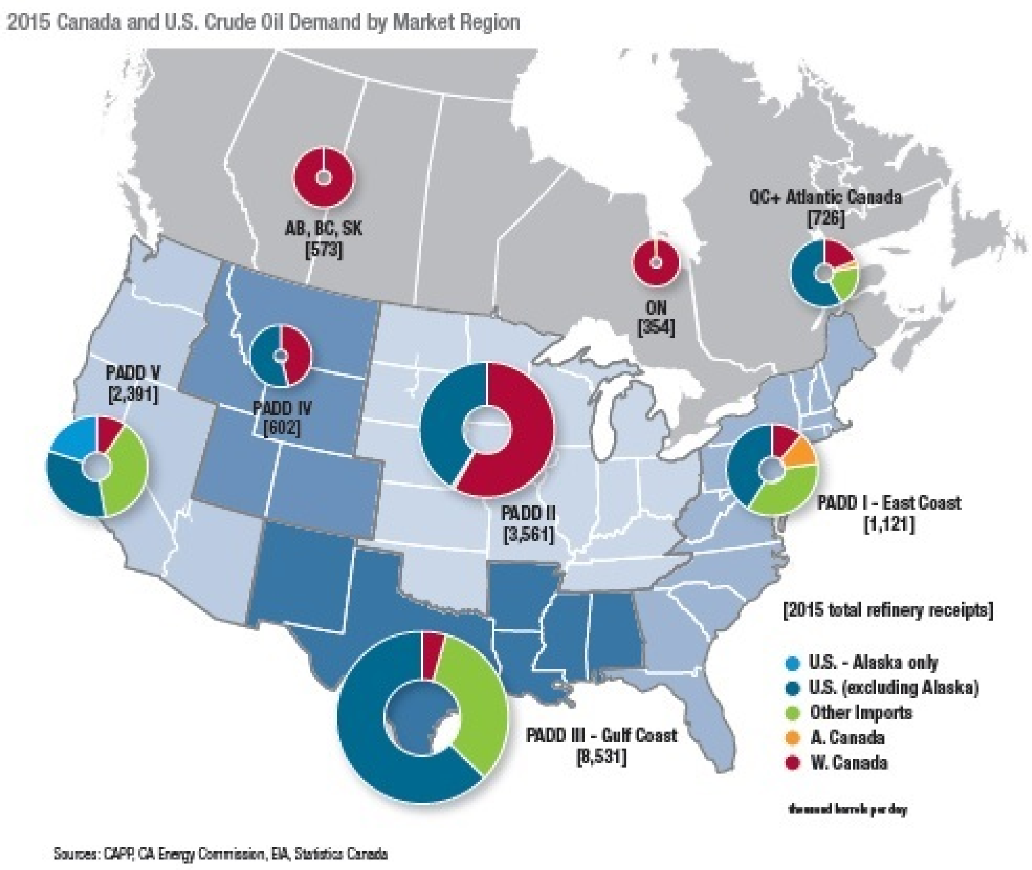
2.3.7 U.S. and Canada Refining Capacity

U.S. refineries are set up to refine light, medium, and heavy types of crude, and they import all types of crude to refine. The U.S. has more refining capacity than crude it produces and imports almost half of the crude it refines. In 2015, the total U.S. refining capacity was 18 MM bpd, and they were operating at approximately 90% capacity [6]. The U.S. has a total of 141 refineries with a total capacity of 18.3 MM bpd. Refer to Table 2 for a breakdown of U.S. refinery capacity by PADD [9].

Table 2: Number and Capacity of U.S. Petroleum Refineries by PADD as of January 1, 2016 [9].

Location	Number of Operable Refineries			Capacity (Barrels per Calendar Day)		
	Total	Operating	Idle	Total	Operating	Idle
PADD 1	9	9	0	1,277,500	1,318,000	35,000
PADD 2	27	27	0	3,922,200	4,197,947	23,000
PADD 3	57	57	0	9,514,745	10,117,755	0
PADD 4	17	16	1	678,550	705,400	14,500
PADD 5	31	30	1	2,924,041	3,006,000	90,000
U.S. Total	141	139	2	18,317,036	19,345,102	162,500

Canada has 16 refineries with a total of 1.9 MM bpd processing capacity. In 2015, only 27% of WCSB crude oil was refined domestically. The remaining oil sand crude oil was sent to the U.S. for refining. This is due to a lack of transportation infrastructure from the WCSB to the refineries on the east coast and lack of heavy crude refining capacity. Refer to Figure 13 for total refining demand per day in 2015 for the U.S. and Canada.



Sources: CAPP, CA Energy Commission, EIA, Statistics Canada

AB = Alberta, BC = British Columbia, ON = Ontario, QC = Québec, SK = Saskatchewan, A. Canada = Atlantic Canada, W. Canada = Western Canada

Figure 13: 2015 Total Refinery Receipts of Canada Crude Oil in Thousand Barrels per Day [13].

2.4 President Obama Energy and Climate Change Policies

President Obama's goals for energy, climate change and the environment were cited in the President's press release as one of the reasons the KXL Pipeline presidential permit was denied. This section outlines the key points in the administration's energy and climate change policy.

2.4.1 Advancing American Energy

President Obama initiated an All-of-the-Above Energy Strategy in order to make America more energy independent [26]. The main points of the plan seek to:

1. Reduce dependence on foreign crude oil;
2. Increase safe and responsible domestic crude oil and gas production;
3. Institute carbon capture and sequestration technologies to reduce emissions;
4. Advance clean energy;
5. Advance energy efficiency;
6. Develop clean fuels; and
7. Invest in coal communities, workers, and technology (POWER+ Plan).

The KXL Pipeline presidential permit denial noted that the Pipeline project did not reduce dependence on foreign crude oil and WCSB crude oil was not considered a cleaner energy source since it required more energy and produced more emissions for extraction than other forms of petroleum crude oil that were lighter in weight [27].

2.4.2 Climate Action Plan

President Obama outlined the Climate Action Plan (CAP) in June 2013 to combat climate change [28]. The CAP consisted of three pillars:

1. Cut carbon pollution in America;
2. Prepare the U.S. for the impacts of climate change; and
3. Lead international efforts to combat global climate change and prepare for its impacts.

2.4.2.1 First Pillar: Cutting Carbon Pollution in America

The strategy for the first pillar (cutting carbon pollution in America) focused on working with new and existing power plants, the building industry, and the automotive industry to reduce GHG and other emissions from sources. The first pillar would also provide funding to advance technology and seek to find ways to increase renewable energy uses on public property and military bases. Finally, the strategy also set a goal to reduce carbon pollution by 3 million metric tons of carbon pollution by 2030 [29].

2.4.2.2 Second Pillar: Prepare the U.S. for Climate Change Impacts

The second pillar identified ways for the federal government to provide more information, resources, and methods to work with state, local and tribal governments and organizations to implement climate-resilient programs more efficiently. Flooding, drought, and wildfires were natural disasters expected to happen with more frequency because of climate change. The pillar identifies ways the federal government can work with local governments and communities to provide them with resources and tools to deal with these natural disasters [29].

2.4.2.3 Third Pillar: Lead International Efforts to Address Global Climate Change

The strategy for the third pillar acknowledges that climate change reductions and effects are global issues requiring partnerships with other countries to be effective. Key points were for the U.S. to work with other major emitters (e.g., China and India) to establish and follow international initiatives. The Obama climate change plan also wanted the U.S. to be a leader in public financing of clean energy locally and abroad [29].

2.5 U.S. and Canada GHG Reporting Programs

In order to track GHG emissions and statistics, many nations are enacting mandatory GHG reporting programs (GHGRPs). Regulatory agencies use these statistics to determine emission regulations and set reduction goals. Canada and the U.S. both have mandatory GHGRPs.

2.5.1 Canadian GHGRP

Canada introduced a GHGRP under Section 46 of the Canadian Environmental Protection Act (CEPA) in March 2004. In Canada, facilities that emit 50,000 metric tons CO_2e or more of GHGs per year are required to report their emissions annually by June 1st. The program is managed by Environment and Climate Change Canada (ECCC) [30].

2.5.2 U.S. GHGRP

The U.S. also has a GHGRP regulated under 40 Code of Federal Regulations (CFR) Part 98 and managed by the U.S. Environmental Protection Agency (U.S. EPA). The GHGRP rule was enacted in the U.S. in 2008. The regulation requires all facilities that emit 25,000 metric tons CO_2e or more per year to report their emissions to the U.S. EPA.

2.6 Keystone Pipeline System

The KXL Pipeline was proposed to transport 800,000 bpd of WCSB crude oil from Alberta, Canada and 30,000 bpd of LTO crude from storage areas in Montana in the U.S. to the U.S. PADD 3 refineries in the Gulf of Mexico. PADD 3 has the most refineries and the largest capacity for refining heavy crude oils. The KXL Pipeline was planned to be the fourth phase of the Keystone System. The first phase was constructed from Hardisty, Alberta to Patoka, Illinois. A Presidential Permit for this phase was approved by the Bush

State Department in March 2008. Phase 2 extended the Pipeline from Steele City, Nebraska to Cushing, Oklahoma. Cushing is a major crude oil hub in the petroleum industry. The third phase extended the Pipeline from Cushing, Oklahoma to Liberty County, Texas and then Houston, Texas. The fourth phase was the leg of the pipeline from Hardisty, Alberta to Steele City, Nebraska that required the presidential permit for the U.S.-Canada border crossing. Refer to Figure 14 for a map of the entire Keystone System [14]. The Keystone Pipeline System would have been the second largest pipeline system exporting oil sands crude from the WCSB region.

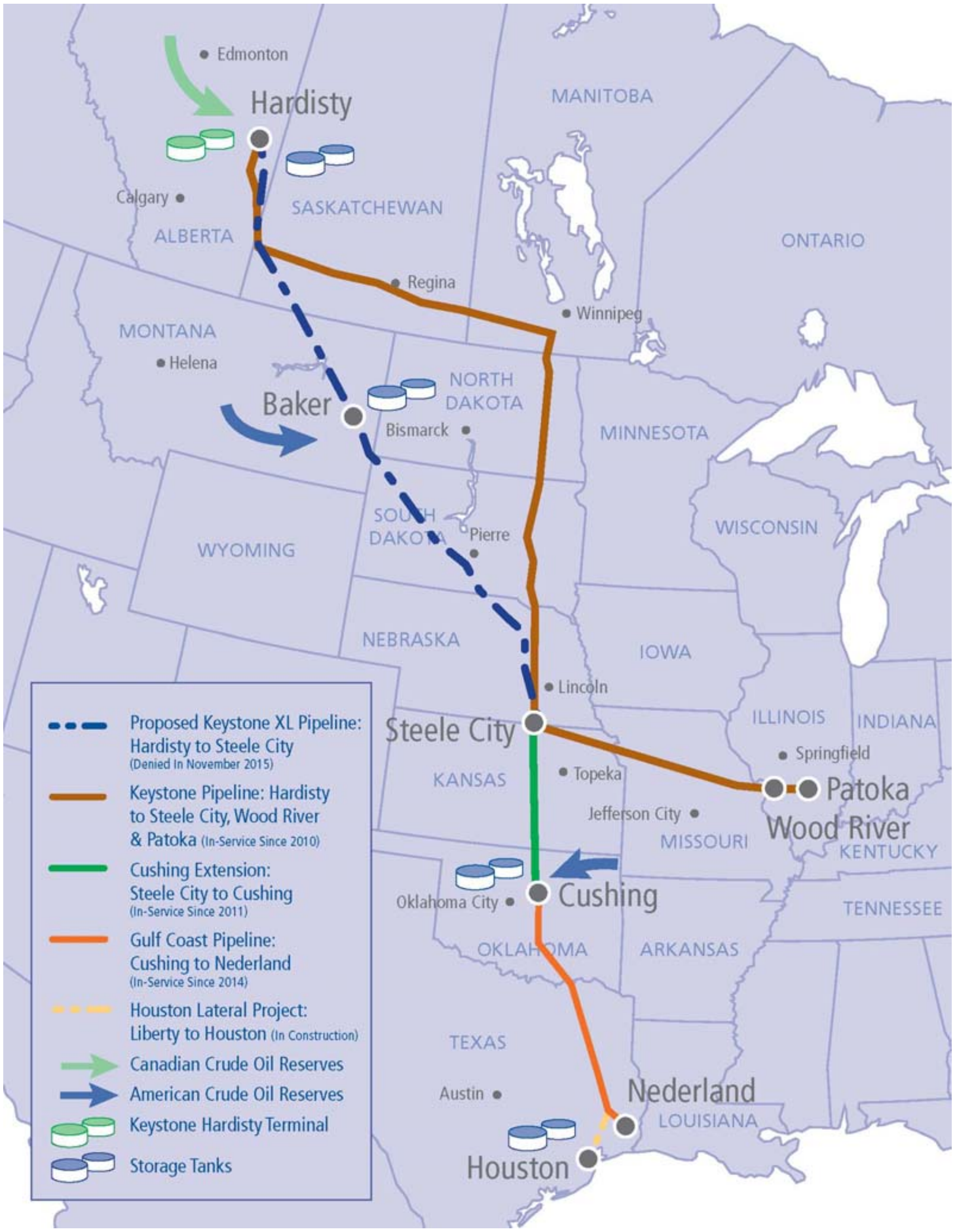


Figure 14: Proposed Keystone XL Pipeline Route Submitted in 2012 [14].

TransCanada initiated the process for the KXL Pipeline in 2008, and it was over seven years later in 2015 before they had a final ruling from the U.S. government. Refer to Figure 15 for a brief timeline of events [14]. The initial KXL route proposed in 2008 included all the segments in Phases 2 through 4, was 1,384 mi. long, and crossed through six states (Montana, South Dakota, Nebraska, Kansas, Oklahoma, Texas). One of the biggest stumbling blocks to approval of the 2008 route was crossing over the Sand Hills aquifer in Nebraska which is the source of drinking water for many Nebraskans. Congress passed a bill in November 2011 that set a deadline for making a decision on the application. This prompted President Obama to deny the permit saying there wasn't time to properly evaluate the risk to the Sand Hills aquifer or alternative routes [12].

Figure 15: KXL Application Timeline [14].

TransCanada broke up the 2008 route into three segments/phases. This allowed them to proceed with the two segments from Kansas to Texas (Phase 2 and 3). Without the international border crossing, TransCanada was free to permit solely with the individual states and tribes for these segments. They received approval from the states and the last segment will be brought online in 2017 [14].

The fourth phase included the international border crossing from Hardisty, Alberta to Steele City, Kansas. The route was nearly identical to the 2008 application, except a different route (bypassing the Sand Hills in Nebraska) was selected. The 2012 route was reduced to 875 mi. long and only crossed through three U.S. states (Montana, South Dakota, and Nebraska) [12].

2.7 Presidential Permit

Any structure conveying goods or services across the international border between Canada and the U.S. requires a U.S Presidential Permit in addition to the Canadian, provincial, state, and tribal permits and authorizations.

2.7.1 U.S. Federal Authority and Presidential Permit Process

President Grant was the first president to assert his authority to approve or deny cross-border permits for the installation of a telegraph cable. Since then, President Lyndon B. Johnson delegated the authority to issue permits to the Secretary of State for “(i) pipelines, conveyor belts, and similar facilities for the exportation or importation of petroleum, petroleum products, coal, minerals, or other products to or from a foreign country; (ii) facilities for the exportation or importation of water or sewage to or from a foreign country; (iii) monorails, aerial cable cars, aerial tramways and similar facilities for the transportation of persons or things, or both, to or from a foreign country; and (iv) bridges, to the extent that congressional authorization is not required" in Executive Order (EO) #11423, Aug. 16, 1968 [31]. The Secretary of State is to contact the Secretaries of Treasury, Defense, Interior, Commerce, and Transportation, Attorney General, Interstate Commerce Commission, and Director of the Office of Emergency Planning for their views and can publish for a public comments period. Authority to determine if the issue is in the "national interest" and therefore approve, set terms, or deny permit rests with the Secretary of State unless one of the departments indicate they disagree and request the matter be referred to the President [32].

EO #13337, April 30, 2004 (President Bush) amended EO #11423 to expedite the process. Major changes included detailing the processes the Secretary of State should take and setting time limits. The agencies to be contacted were also updated and provisions made for future changes to cabinet. The Secretary of State was also given authority to consult with State, tribal, and local government officials and foreign governments [33].

The State Department was the lead federal agency reviewing the permit application. As required, the State Department solicited comments from the Departments of Energy, Defense, Transportation, Homeland Security, Justice, Interior, and Commerce, as well as the U.S. EPA.

2.7.2 U.S. State and Tribal Authority

The proposed 2012 KXL Pipeline route crossed through three states (Montana, South Dakota, and Nebraska) and a summary of approvals from the states is summarized below:

- In Montana, the Montana Department of Environmental Quality (MDEQ) was the lead agency for state approval. The MDEQ approved a Certificate for Compliance for the route on March 30, 2012 [12].
- In South Dakota, the lead agency was the South Dakota Public Utilities Commission (SDPUC). The SDPUC approved the segment through South Dakota in June 2010 [12]. Since the route through South Dakota did not change, if/when the State Department approved the 2012 proposed route, TransCanada would have to provide information that the scope had not changed to renew approval from South Dakota.
- In Nebraska, the Nebraska Department of Environmental Quality (NDEQ) was the lead agency for review and approval. On January 22, 2013, the NDEQ approved the route bypassing the Sand Hills in Nebraska [12].

2.7.3 Canadian Authority

In Canada, the National Energy Board (NEB) is the lead agency reviewing the approval process. The NEB approved the KXL Pipeline application for the Canadian portion on March 11, 2010 [12].

2.8 Special Interest KXL Pipeline Debate

The KXL Pipeline proposal sparked debate primarily between environmental groups and the petroleum industry.

2.8.1.1 Pro-Pipeline Arguments

There were both U.S. and Canadian organizations and governments officials in support of the KXL Pipeline, including Canadian Prime Minister Justin Trudeau, U.S.

Senators Mary Landrieu (D-LA), Heidi Heitkamp (D-ND), Joe Manchin III (D-WV), John Hoeven (R-ND), U.S. Representative John Barrow (D-GA), API, and CAPP, to name a few. API and CAPP wrote editorials and participated in research in support of the Pipeline. Those pro-pipeline individuals and groups had similar arguments, including good trading partnership and job creation. Proponents also downplayed the increased GHG emissions compared to conventional oils.

In a post on May 23, 2011 on the API website, Sabrina Fang made the case that the Pipeline would [34]:

- Increase energy security;
- Improve relations with Canada;
- Support 21,000 jobs and $2 billion addition to economy during construction; and
- Support up to 465,000 additional jobs by 2035.

Greg Stringham, Vice President of Oil Sands CAPP, wrote an editorial to the Huffington Post on March 22, 2013 making similar points for the KXL Pipeline [3]. In particular, he noted that the Pipeline would strengthen the U.S.-Canada energy trade partnership between environmentally responsible parties. The article also notes that Canadian oil sands are at 50% of expected extraction capacity, but current pipelines from the oil sands area are operating near capacity. Lastly, Mr. Stringham argued that Canadian oil sands account for 0.16 percent of global GHG emissions, the oil sands industry has reduced GHG emissions by 26% since 1990, and [at the time] Canada was the only country of the top five crude oil importers to the U.S. that had GHG regulations in place.

2.8.1.2 Anti-Pipeline Arguments

Many protests were organized against the KXL Pipeline as well. The Sierra Club posted articles and took out billboards against the Pipeline project. One post by Bob Clark on the Montana Chapter website countered that the oil sands crude oil in Alberta, Canada is the "dirtiest oil on the earth with 11 times more sulfur and nickel and 5 times more lead than conventional oil, emits nearly twice the greenhouse gases, and would exacerbate climate change" [35]. The posting also argued that the jobs numbers claimed by proponents were exaggerated, with the real number of permanent jobs created closer to 55. This particular posting was advocating support for upgrading existing pipelines and transmission lines, and renewable energy instead of the KXL Pipeline.

2.9 Final Supplemental Environmental Impact Statement 2014

In addition to garnering opinions from other federal, state, and local agencies, the State Department is required to prepare an environmental impact statement (EIS) to make a determination on a presidential permit application. An EIS was prepared for the 2008 KXL Pipeline application, and a supplemental version was prepared for the revised 2012 route. This report focuses on the supplemental version. The Final Supplemental Environmental Impact Statement (SEIS), dated 2014, is a comprehensive document that covers many aspects related to the KXL Pipeline proposal. This paper focuses on the GHG emissions portion of the report.

2.9.1.1 Market Analysis

One of the arguments against the KXL Pipeline was related to the energy intensive nature of the WCSB extraction process. The argument indicated that compared to conventional oil, extracting crude from the WCSB not only required more energy (which produced more GHG emissions), but it was also more costly. Since transportation by pipeline is more cost effective than other means of transportation, the KXL Pipeline would indirectly promote more WCSB crude oil extraction, and therefore, GHG emissions, because more money would be available for exploration and well production.

To study this argument, the SEIS modeled four supply-demand scenarios against four pipeline scenarios to gauge the WCSB crude oil extraction rates' sensitivity to transportation costs. The supply-demand scenarios were based on the U.S. EIA 2013 Annual Energy Outlook report and used the World Oil Refining, Logistics, and Demand (WORLD) model. The supply-demand scenarios evaluated effects of high crude-oil and natural gas resources in the U.S., low U.S. consumption rates, and high availability of Latin America crude oil imports [12]. The pipeline scenarios evaluated the effects of no new pipelines approved in U.S. or Canada, unrestricted pipeline construction in both countries, cross-border pipelines approved without approval for additional internal Canadian pipelines, and internal Canadian pipelines approved without approval for cross-border pipelines [12].

The WORLD modeling results indicated cross-border constraints have a limited impact on WCSB crude oil extraction and crude oil prices [12]. In summary:

- If no pipelines, the crude oil would be transported via other methods (e.g., rail);
- If not to the U.S., then Canada would explore other markets (e.g., Asian, Europe, etc.); and

- If the U.S. doesn’t import heavy crude from Canada, then they would import from other markets including other oil sand markets (e.g., Latin America, Middle East, etc.).

The SEIS predicts that a crude oil price of $75 per barrel for WTI-equivalent crude oil or more would allow revenues of oil sand producers to remain above supply costs. A breakeven range was predicted to be $65 to $75 per barrel. Further, the SEIS predicted that sustained crude oil prices below $75 per barrel and higher transportation costs would reduce oil sands production. However, SEIS concluded that it would be unlikely that low crude prices would be sustained long enough to impact oil sands production, because the petroleum industry would have the resources to continue to invest until crude oil prices went up above the breakeven point [12].

2.9.1.2 GHG Emissions Calculations

The SEIS sought to determine the incremental life-cycle assessment (LCA) GHG emissions between WCSB transported through the Pipeline and refined in the U.S. to four reference crude oils also refined in the U.S. and considered to be the most likely alternatives. The SEIS evaluated life-cycle GHG emissions from the point of crude oil extraction through transportation, refining, distribution, and consumption of refined products by end users. This is called a well-to-wheel (WTW) analysis. Refer to Figure 16 for an illustration of WTW boundary [12].

The SEIS reviewed 28 different sources from individual researchers, government organizations, university sponsored work, engineering consulting firms, and various modeling programs to determine life-cycle GHG emissions for 830,000 bpd of WCSB crude oil and the four reference crudes. Life-cycle GHG emissions from the following crude oil sources were compared in the SEIS [12]:

- Baseline crude - average U.S. barrel consumed in 2005,
- WCSB crude,
- Venezuela Bachaquero crude - largest oil sand proven reserve in the world and likely alternative to WCSB crude imports into the U.S.,
- Mexican Maya crude - heavy crude also considered likely alternative to WCSB crude imports into the U.S., and
- Middle East Saudi Light crude - not a heavy crude oil, but still considered viable alternative to WCSB import because it is the largest proven reserve in the world and has the capacity to increase product to balance demand.

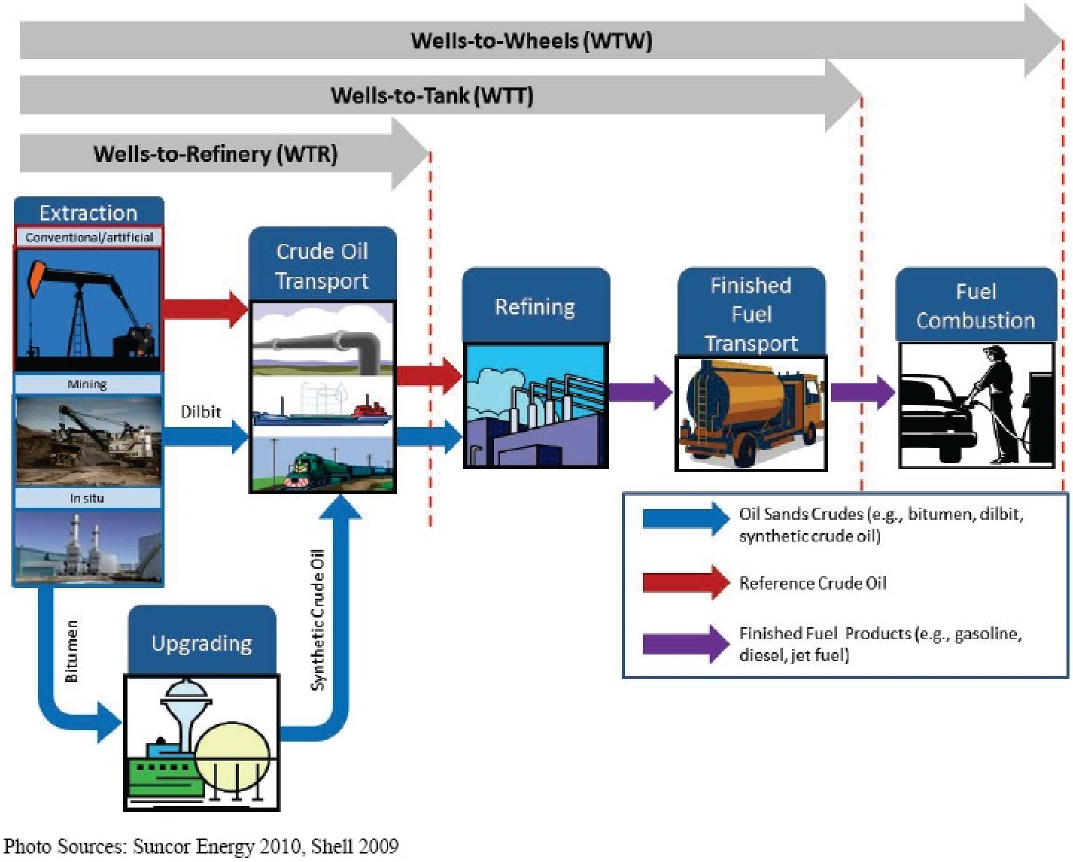
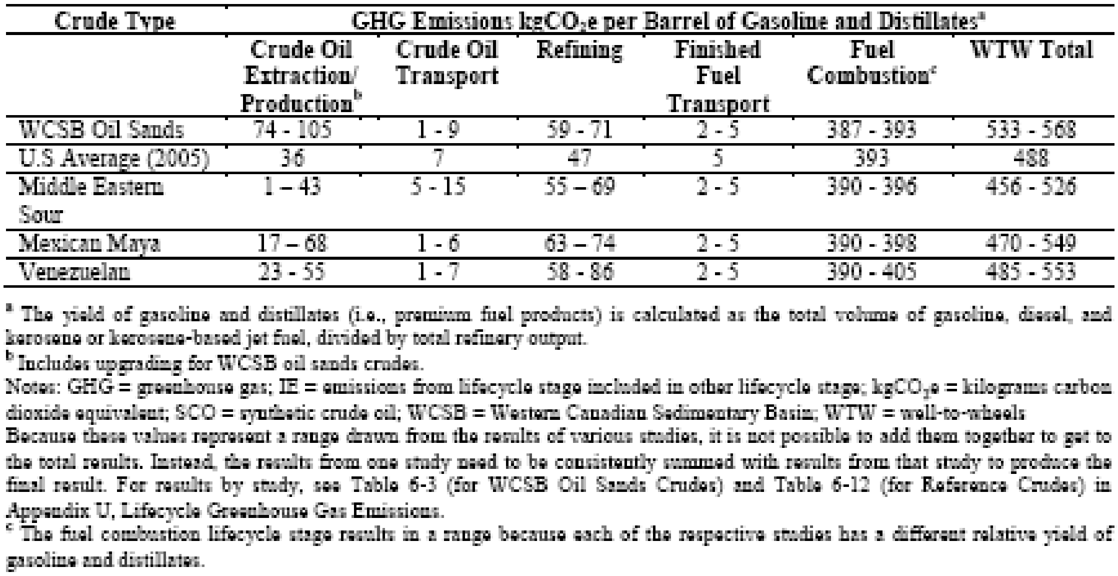


Figure 16: Crude Oil Life-cycle Boundaries [12].

The SEIS concluded that the life-cycle GHG emissions for WCSB crude refined in PADD3 and traveling through the KXL Pipeline would generate 533 to 568 kilograms of carbon dioxide equivalent (kg CO_2e) per barrel of refined gasoline produced. Life-cycle GHG emissions from the four other crude oils evaluated ranged from 456 to 553 kgCO_2e [12]. Refer to Table 3 for the SEIS summary of GHG emissions by life-cycle stage and crude oil type.

Table 3: Ranges of WTW GHG Emissions per Barrel for Weighted-Average Crudes by Life-cycle Stage [12].



Crude Type	GHG Emissions $kgCO_2e$ per Barrel of Gasoline and Distillates[a]					
	Crude Oil Extraction/ Production[b]	Crude Oil Transport	Refining	Finished Fuel Transport	Fuel Combustion[c]	WTW Total
WCSB Oil Sands	74 - 105	1 - 9	59 - 71	2 - 5	387 - 393	533 - 568
U.S Average (2005)	36	7	47	5	393	488
Middle Eastern Sour	1 – 43	5 - 15	55 – 69	2 - 5	390 - 396	456 - 526
Mexican Maya	17 – 68	1 - 6	63 – 74	2 - 5	390 - 398	470 - 549
Venezuelan	23 - 55	1 - 7	58 - 86	2 - 5	390 - 405	485 - 553

[a] The yield of gasoline and distillates (i.e., premium fuel products) is calculated as the total volume of gasoline, diesel, and kerosene or kerosene-based jet fuel, divided by total refinery output.

[b] Includes upgrading for WCSB oil sands crudes.

Notes: GHG = greenhouse gas; IE = emissions from lifecycle stage included in other lifecycle stage; $kgCO_2e$ = kilograms carbon dioxide equivalent; SCO = synthetic crude oil; WCSB = Western Canadian Sedimentary Basin; WTW = well-to-wheels

Because these values represent a range drawn from the results of various studies, it is not possible to add them together to get to the total results. Instead, the results from one study need to be consistently summed with results from that study to produce the final result. For results by study, see Table 6-3 (for WCSB Oil Sands Crudes) and Table 6-12 (for Reference Crudes) in Appendix U, Lifecycle Greenhouse Gas Emissions.

[c] The fuel combustion lifecycle stage results in a range because each of the respective studies has a different relative yield of gasoline and distillates.

2.10 U.S. National Interest Determination

In November 2015, the U.S. State Department determined that approving a presidential permit for the KXL Pipeline would not serve the "national interest". This decision was supported by President Obama and the eight federal agencies consulted as part of the process. In a press statement made by Secretary of State John Kerry on November 6, 2015, he stated his decision was based on key findings by the State Department that:

- *The proposed project has a negligible impact on [U.S.] energy security.*
- *The proposed project would not lead to lower gas prices for American consumers.*
- *The proposed project's long-term contribution to [the United States'] economy would be marginal.*
- *The proposed project raises a range of concerns about the impact on local communities, water supplies, and cultural heritage sites.*

- *The proposed project would facilitate transportation into [the U.S.] of a particularly dirty source of fuel* [36].

The last statement was the focus of the decision juxtaposed against the administration's energy policy and CAP. On the same day, President Obama also released a statement supporting the State Department's decision with the overarching theme that this decision supports America’s position as a global leader on fighting climate change and setting an example for the rest of the world on how to make the hard decisions needed to fight climate change [1].

Chapter 3 Materials and Methods

As previously stated, both Secretary of State Kerry and President Obama sought to reduce GHG emissions in the U.S. and the world by denying the presidential permit for the KXL Pipeline, thereby limiting new pipeline capacity and restricting WCSB crude oil transportation to more expensive and less efficient modes of transportation (i.e., rail, barge, truck). The intended goal was to reduce the amount of WCSB crude oil entering the U.S. and, more broadly, the amount of crude oil extracted from the oil sands. The underlining message was that the oil sands crude is too energy intensive and generates too many GHGs to be removed from the ground for use. The purpose of this paper is to determine how effective denying the presidential permit for the KXL Pipeline was in reducing GHG emissions from WCSB crude oil.

3.1 Alternative Modes of Transportation into the U.S.

The SEIS reviewed WTW life-cycle GHG emissions for the KXL Pipeline compared to four reference crudes used in the U.S. This paper will compare and contrast a well-to-refinery (WTR) LCA using three different modes of transportation (pipeline, rail, and barge) for WCSB crude oil only. Since the destination includes the same refineries, emissions from refining were not evaluated. Likewise, this paper assumes that GHG emissions from transportation of the refined products to distributors and combustion of the refined products by end users would be the same for all crude oil transportation methods.

3.1.1 Petroleum Industry GHG Models

Four different models developed to calculate life-cycle emissions from the transportation and petroleum industries were reviewed for use in this paper. A summary of each model and the evaluation parameters is provided in Table 4.

Table 4: GHG Emission Models.

CRITERIA	**GHGenius** [37]	**GREET** [38]	**OPGEE** [39]	**GHOST** [40]
Developer	S&T Squared Consultants, Inc.	Argonne National Lab Systems	Stanford Dept. of Energy Resources Eng.	University of Calgary
Sponsor	Natural Resources Canada	U.S. DOE	California Air Resources Board (CARB)	University of Calgary
Data Source	Public data from U.S., Canada, Mexico, and India	Public data from U.S.	Public data from U.S.	Private Industry data
Last Revision	March 2013	October 2016	June 2015	N/A
Boundary	WTW	WTW	WTR	WTW
Results	GHGs, Air Pollutants, Energy Use	GHGs, Air Pollutants, Energy Use	GHGs, Air Pollutants, Energy Use	GHGs
Copyright	Public, Open Source	Public, Open Source	Public, Open Source	Private

The OPGEE model was selected for use in this paper because it had recent data and had the best options for customizing the transportation modes for the different scenarios.

3.1.2 Transportation Scenarios

Three different modes of transportation were evaluated to determine relative GHG emissions—pipeline, railcar, and barge. Each of these modes of transportation are currently being used to transport WCSB crude oil to the U.S. Refer to Table 5. The comparison will use a transportation quantity of 830,000 bpd for each mode since that was the design capacity of the KXL Pipeline. For simplicity sake, the scenarios evaluated will assume all the crude oil originates from the WCSB instead of 95/5 split between WCSB and U.S. stock piles. All modes of transportation evaluated will transfer crude oil from the stockpile in Hardisty, Alberta (KXL Pipeline origin) to Port Arthur, Texas (Pipeline destination) to determine if fewer GHGs would be emitted with other transportation modes into the U.S.

Table 5: Alternative Transportation Scenario Inputs.

	Scenario 1: Pipeline	**Scenario 2: Railcar**	**Scenario 3: Barge**
Common Assumptions	• 830,000 bpd WCSB crude oil • SAGD extraction method • 40-year Well Field Life • 100 bpd/ well • 8,300 well pairs • Average well depth of 550 feet • Crude Oil Degree API = 8 • Original land use forested	• 830,000 bpd WCSB crude oil • SAGD extraction method • 40-year Well Field Life • 100 bpd/ well • 8,300 well pairs • Average well depth of 550 feet • Crude Oil Degree API = 8 • Original land use forested	• 830,000 bpd WCSB crude oil • SAGD extraction method • 40-year Well Field Life • 100 bpd/ well • 8,300 well pairs • Average well depth of 550 feet • Crude Oil Degree API = 8 • Original land use forested
Scenario Parameters	• Transporting dilbit (30% diluent/70% bitumen) • ~1985 mi. by KXL Pipeline from Hardisty, Alberta to Port Arthur, TX	• Transporting railbit (15% diluent/85% bitumen) • ~2485 mi. by railcar from Hardisty, Alberta to Port Arthur, TX	• Transporting railbit (15% diluent/85% bitumen) • ~1133 mi. by railcar from Hardisty, Alberta to St. Paul, MN and 2200 mi. by barge from St. Paul, MN to Port Arthur, TX
Modeled Route	Figure 14	Figure 17	Figure 18

Figure 17: Rail Distances and Cycle Times to Major Markets [41].

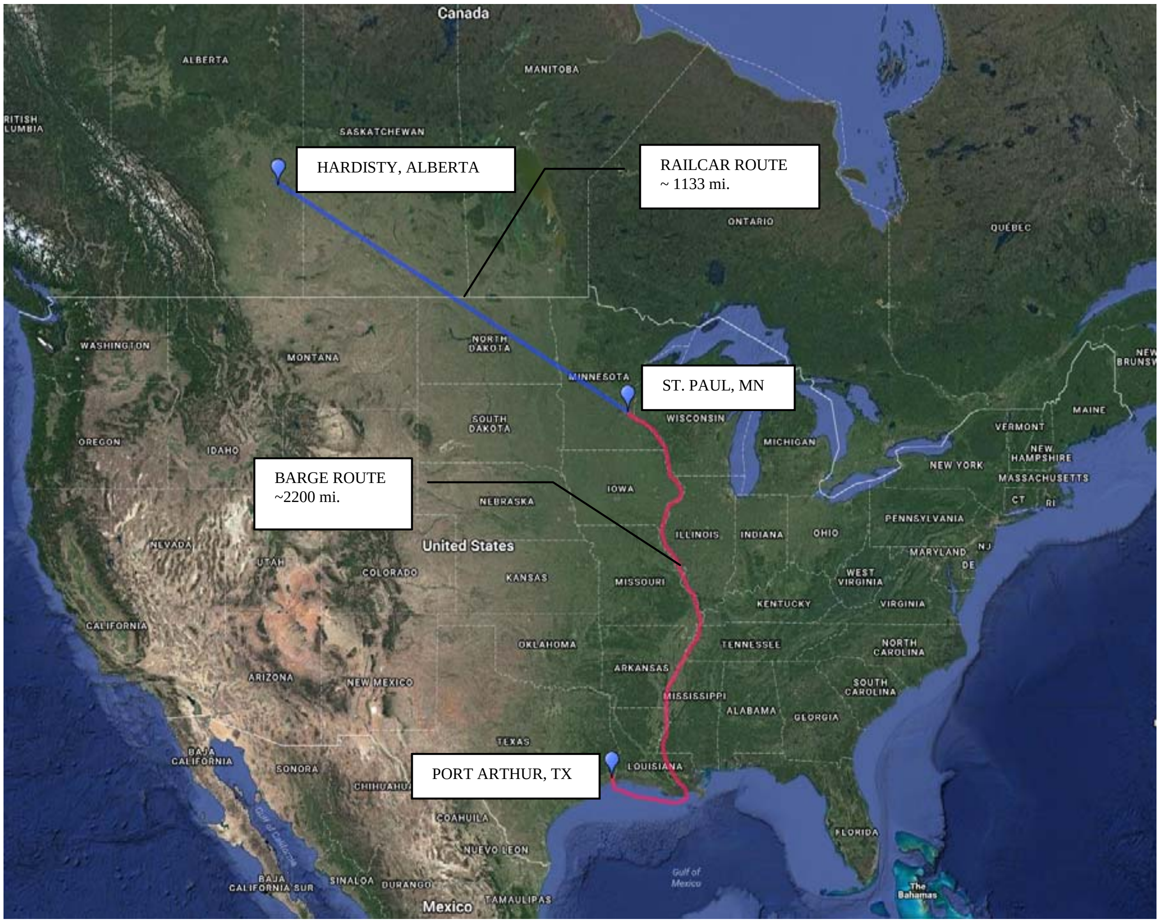


Figure 18: Railcar/Barge Route.

3.2 Actual WCSB Production and Transportation Since 2013

As previously stated, the State Department expected to reduce GHG emissions from oil sands by reducing imports of WCSB into the U.S. and by making it more expensive to transport crude oil in lower petroleum markets, which would discourage more extraction wells. To evaluate this prediction in light of the dip in market value of crude oil per barrel, this paper will review present and future projections of WCSB production, imports into the U.S., and import destination.

Chapter 4 Results and Discussion

The purpose of this paper is to review the potential GHG emissions for different modes of transporting WCSB crude oil from Canada to the Gulf of Mexico area for refining and what impact the State Department's decision had on WCSB crude oil production. By comparing the GHG emissions from different transportation scenarios and reviewing WCSB crude oil production and export rates, the paper will evaluate the intended and unintended consequences of the decision to prevent construction of the KXL Pipeline as it relates to GHG emissions and climate change. The intended consequences of the action were to limit well production in the WCSB, especially if the price per barrel of crude fell below the breakeven point of $50-$60/barrel, and keeping crude in the ground.

4.1 Alternative Transportation Modes Impacts on GHG Emissions

Three different transportation scenarios (pipeline, railcar, and barge) were selected to determine the variation in GHG emissions from transporting 830,000 bpd of crude oil from Hardisty, Alberta to Port Arthur, Texas. The OPGEE model was used to calculate WTR GHG emissions for all three scenarios. A summary of the OPGEE model inputs are included in Table 5, and a summary of the results is presented in Table 6. The full model inputs and results are provided in Appendix A.

The results of the model indicate that just for the transportation phase, transportation by railcar and barge produce almost two and five times the GHG emissions, respectively, as transportation by pipeline. However, transportation emissions is a small percentage of the life-cycle emissions for the scenario, and the difference between total emissions for each scenario is 10% or less. While it is accurate to say that transportation by barge produces more GHG emissions than by railcar and by pipeline, the overall effect on life-cycle GHG emissions is small.

Table 6: Summary of GHG Emissions for Different Transportation Modes [gCO$_2$e/MJ].

	Scenario 1: Pipeline		**Scenario 2: Railcar**		**Scenario 3: Barge**	
Process Description	**gCO$_2$e/ MJ crude oil** [g]	**kgCO$_2$e/bbl gasoline** [h]	**gCO$_2$e/ MJ crude oil** [g]	**kgCO$_2$e/bbl gasoline** [h]	**gCO$_2$e/ MJ crude oil** [g]	**kgCO$_2$e/bbl gasoline** [h]
Drilling [a]	*6.47*	53.5	*6.47*	53.5	*6.47*	53.5
Production [b]	*9.48*	78.5	*11.3*	93.5	*11.3*	93.5
VFF [c]	*2.77*	22.9	*3.3*	27	*3.3*	27
Miscellaneous [d]	*0.5*	4	*0.5*	4	*0.5*	4
Crude Oil Transportation [e]	*0.95*	7.9	*2.01*	16.6	*4.61*	38.2
Offsite emissions [f]	*6.22*	51.5	*5.04*	41.7	*5.04*	41.7
Net life-cycle emissions	***26.39***	**218**	***28.62***	**237**	***31.23***	**258**

a. Drilling includes emissions from motors/engines, venting, and land use impacts.
b. Production includes emissions from lifting product, injection steam and/or additives. Variations in production are due to differences in diluent ratios required for different transportation modes. More diluent is required to transport crude oil through pipeline than railcar or barge.
c. VFF = Venting, flaring, and fugitive emissions.
d. Miscellaneous is a standard number added in the model to account for small sources not specifically calculated.
e. Transportation represents emissions from the fuel combustion by selected transportation mode and distance traveled.
f. Offsite emissions is a credit or debit based on imports/exports of fuels used in life-cycle process.
g. OPGEE model reports results in grams of carbon dioxide equivalent emissions per mega joule (gCO$_2$e/MJ). Results converted to kilograms carbon dioxide equivalent emissions per barrel gasoline and distillates (kgCO$_2$e/bbl gasoline) by using conversion factors of 1,000 g/kg; 6,437 MJ/bbl crude; and 0.78 bbl gasoline and distillates/bbl crude.

4.2 Alternative Crude Oil Source Impact on GHG Emission

To determine the impact WCSB crude oil would have on climate change, the SEIS compared WTW life-cycle GHG emissions from WCSB crude oil and four other reference crudes refined in the United States (Table 3). The difference between the total emissions for each crude oil was 10% or less. If only the heavy or extra heavy crude oils (WCSB oil sands, Mexican Maya, Venezuela oil sands) are compared, the difference between these three is 3% or less. These four crudes were selected because the speculation was that if WCSB crude oil was not imported because the Pipeline was not constructed, one of the other sources would be imported instead. In the last 5 years, Canadian imports have increased even without the Pipeline construction, while imports from Mexico, Venezuela, and Saudi Arabia have decreased. This suggests that WCSB crude oil exports to the U.S. have a low sensitivity to the availability of pipeline transportation, and that there are other factors that make this trade relationship desirable.

While it is accurate to say that WCSB life-cycle GHG emissions are on the higher end when compared to these reference crudes, the difference between WCSB crude oil and other heavy/extra heavy crude oils is not significant. It is important to note that the crude oil transportation leg of the SEIS analysis represents 1 - 3% of the total GHG emissions per barrel finished product. The life-cycle stage that had the most GHG emissions was finished fuel combustion at nearly 70 - 80% of total GHG emissions per barrel finished product. The greatest potential for GHG emission reductions is in this final stage. Additionally, reducing fuel combustion GHG emissions would reduce life-cycle emissions from all types of crude oil. Transportation of crude oil and finished fuel has the smallest potential for impact on life-cycle GHG emissions.

4.3 WCSB Crude Oil Production

As stated previously, one of the intended consequences for denying the presidential permit for the KXL Pipeline border crossing was to limit well production in the WCSB and reduce GHG emissions by keeping crude in the ground [27, 35]. The breakeven price for WCSB crude oil was estimated to be \$50-\$60/bbl [12]. Since pipeline is the most cost effective option for crude oil transportation, the argument was WCSB crude oil producers would have higher breakeven margins when they used railcar or barge transportation methods. This would increase the likelihood that a drop in crude oil price would make it too expensive to extract WCSB crude oil from the ground.

Since 2014, the WTI price per barrel has been below $60/barrel (Figure 4). Opponents of the Pipeline predicted that WCSB crude oil production would decrease in this scenario because the producers would not be able to make a profit. Between 2014 and 2016, there has been a slight dip in production (Figure 9). According to the CAPP 2016 Crude Oil Forecast, Markets, and Transportation Report, this dip is mostly attributed to wildfires in Alberta that shut down production of nearby wells. Additional data would be needed to determine how much of this dip was attributed to a singular event (wildfires) or a sustained drop in crude oil prices.

4.4 WCSB Crude Oil Exports to the U.S.

Another reason stated for denying the presidential permit for the KXL Pipeline border crossing was to reduce imports of "dirty" crude oil into the U.S. [27, 35]. Because of the additional energy required to extract crude oil from oil sands, WCSB crude oil was labeled "dirty oil" by opponents of the Pipeline. Preventing the Pipeline construction was intended to reduce imports of WCSB crude oil into the U.S. However, Canadian imports of crude oil have increased every year since 2005 (Figure 11) and most of that increase was from the Western Canada oil sands region [13].

Chapter 5 Conclusions and Recommendations

5.1 Conclusions

The State Department's goal when denying the presidential permit for the KXL Pipeline was to reduce GHG emissions by preventing WCSB from being imported into the U.S. and reducing crude oil production from the WCSB area, particularly if the price of crude oil decreased from 2013 rates. This paper sought to evaluate these goals and determine whether GHG emissions were reduced for the WCSB crude oil. Were those goals achieved as of 2016?

- Did preventing the Pipeline construction reduce WCSB crude oil GHG emissions by the use of alternative modes of transportation to the U.S.? *No, but not significantly. Rail and barge produce more GHG emissions per barrel of refined product than transportation via pipeline. However, the life-cycle GHG emissions for the different transportation modes were within 10% of each other.*
- Did preventing the Pipeline construction reduce GHG emissions by importing more crude oil from alternative sources? *No. While alternative crude oil sources have lower life-cycle greenhouse gas emissions, WCSB crude oil imports to the U.S. have increased every year for the past five years despite the fact the Pipeline was not constructed. Additionally, other import sources have decreased over the same period.*
- Did preventing the Pipeline construction reduce GHG emissions by leaving crude in the ground? *Maybe. There was a small dip in WCSB crude oil production rates in 2015 that were attributed to nearby wildfires. However, the price per barrel of crude oil also decreased below breakeven levels since 2014. More data are*

needed to determine if the dip in production is solely due to nearby wildfires or also the result of lower crude oil prices.

- Did preventing the Pipeline construction reduce GHG emissions by reducing exports of WCSB crude to U.S.? *No. WCSB crude imports to the U.S. have increased every year for the past five years.*

5.2 Recommendations

The conclusions of this report indicate that denying the KXL Pipeline did not significantly reduce GHG emissions from the WCSB crude oil and may have increased GHG emissions by forcing transportation via alternative methods that produce more GHG emissions, though not significantly. If the price of crude oil continues to remain below the breakeven level for WCSB crude oil production, this information should be reviewed again. Given the results in this paper based on current information, this author would not recommend preventing the Pipeline based on GHG emissions only. Other factors such as environmental impacts, safety, energy security, trading relationships, environmental responsibility of source country, etc. should be evaluated.

To have a greater impact on GHG emissions from petroleum products, this author would recommend policy that reduces emissions from refined product combustion or encourages reductions in consumption, since this life-cycle stage represents 70-80% of the total emissions. Alternatively, it is not disputed that heavier crude oils require more energy to handle and therefore have higher life-cycle GHG emissions. However, differences in emissions from different heavy crude oil sources are not significant. To have a greater impact, this author would recommend considering policy that reduces all heavy crude oil imports and encourages refineries to alter operations in favor of conventional crude oil.

5.3 Additional Research Recommended

The modeling performed in this paper did not include transportation of WCSB crude oil via truck. While truck traffic is mostly used to transport refined products, it is also used for crude oil transportation and should be evaluated for comparative GHG emissions to pipeline transportation. Other things that should be considered are:

- How future emission regulation caps would affect WCSB emissions;
- How future extraction regulations caps would affect WCSB emissions;
- Environmental impacts, safety, GHG emissions from spills for pipelines versus other modes of transportation; and
- Other emissions from transportation (hazardous pollutants, particulate matter, etc.).

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APPENDIX A

Alternative Modes of Transportation GHG Emission Model

In this capstone project, the OPGEE GHG Emission Model was employed to model the GHG impacts of three alternative transportation scenarios for Canadian Oil Sands crude oil. The three alternative transportation modes include barge transport, pipeline transport, and railcar transport. Appendix A features all data inputs and results for the transportation scenarios in the following order, barge, railcar, pipeline.

BARGE SCENARIO

User Inputs and Results - Barge Scenario

1 Summary results

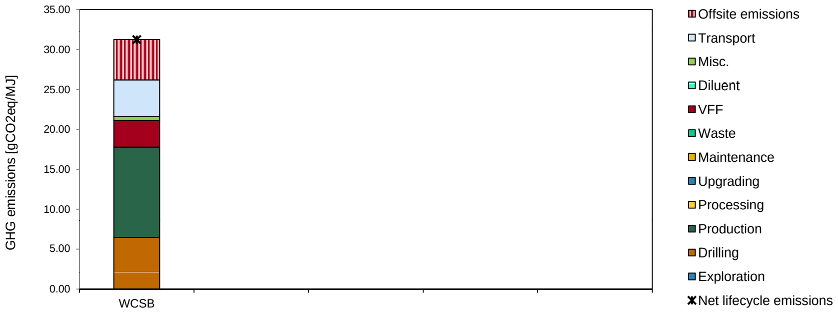
Model error check: **OK**

Table 1.1: Summary GHG emissions

GHG emissions [gCO2eq/MJ]					
	WCSB				
Exploration	0.00				
Drilling	6.47				
Production	11.30				
Processing	0.00				
Upgrading	0.00				
Maintenance	0.00				
Waste	0.00				
VFF	3.30				
Diluent	0.00				
Misc.	0.50				
Transport	4.61				
Offsite emissions	5.04				
Net lifecycle emis	31.23				

Notes: Copy highlighted column and paste 'as numbers' to generate a record

Figure 1.1: Summary GHG emissions

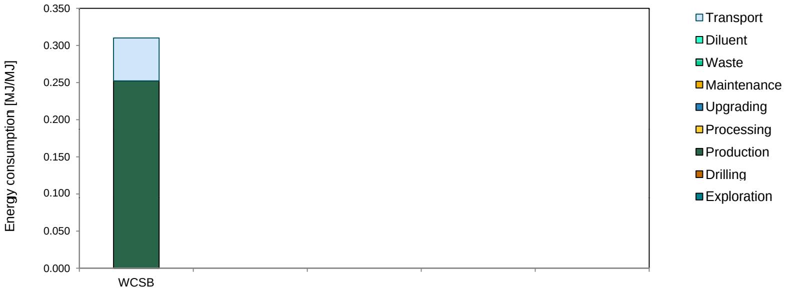


0 Table 1.2: Summary energy consumption

Energy consumption [MJ/MJ]					
	WCSB				
Exploration	0.00				
Drilling	0.00				
Production	0.25				
Processing	0.00				
Upgrading	0.00				
Maintenance	0.00				
Waste	0.00				
Diluent	0.00				
Transport	0.06				
Total	0.310				

Notes: Copy highlighted column and paste 'as numbers' to generate a record

Figure 1.2: Summary energy consumption



2 Petroleum resource

2.1 Conventional	0	1	NA
2.2 Bitumen	1	0	NA
Check:	OK	OK	

3 User inputs - Conventional

Enter primary input parameters and choices	User	Default	Unit	Notes

3.1 Production methods

Note: Enter "1" where applicable and "0" where not applicable

User Inputs and Results - Barge Scenario

3.1.1 Downhole pump		1	1	NA	
3.1.2 Water reinjection		1	1	NA	If water flooding applies then "0"
3.1.3 Gas reinjection		1	1	NA	If gas flooding applies then "0"
3.1.4 Water flooding		0	0	NA	This is used for injecting amounts of water larger than the ar
3.1.5 Gas lifting	OK	0	0	NA	This is used for gas lifting
3.1.6 Gas flooding		0	0	NA	This is used for injecting a different type of gas (e.g. N2) or a
3.1.7 Steam flooding		0	0	NA	This is used for injecting steam

3.2 Field properties

3.2.1 Field location (Country)	OK	Canada	Generic	NA	
3.2.2 Field name		WCSB	Generic	NA	
3.2.3 Field age		40	35	yr	
3.2.4 Field depth		550	7240	ft	
3.2.5 Oil production volume		830000	1500	bbl/d	
3.2.6 Number of producing wells		8300	4536	[-]	
3.2.7 Number of water injecting wells		8300	4416	[-]	
3.2.8 Well diameter		7.0	2.8	in	
3.2.9 Productivity index		3.0	3.0	bbl/psi-d	
3.2.10 Average reservoir pressure		1557	118	psi	Downhole pump on

3.3 Fluid properties

3.3.1 API gravity of produced crude		8	30	deg. API	
3.3.2 Associated gas composition					
	N_2	2.00	2.0	mol%	Composition on dry basis
	CO_2	6.00	6.0	mol%	
	C_1	84.00	84.0	mol%	
	C_2	4.00	4.0	mol%	
	C_3	2.00	2.0	mol%	
	C_4+	1.00	1.0	mol%	
	H_2S	1.00	1.0	mol%	
	Sum				

3.4 Production practices

Notes: Enter "NA" where not applicable

3.4.1 Gas-to-oil ratio (GOR)		908	227	scf/bbl oil	In the case of gas lift, the gas oil ratio should include produc
3.4.2 Water-to-oil ratio (WOR)		4.3	5.5	bbl water/bbl oil	
3.4.3 Water injection ratio	OK	5.3	5.3	bbl water/bbl oil	
3.4.4 Gas lifting injection ratio	OK	1500	1500	scf/bbl liquid	Gas lifting injection (does not include gas reinjected into the
3.4.5 Gas flooding injection ratio	OK	1362	1362	scf/bbl oil	
3.4.6 Steam-to-oil ratio (SOR)	OK	3.0	3.0	bbl steam/bbl oil	
3.4.7 Fraction of required electricity generated onsite		0.00	0.00	[-]	
3.4.8 Fraction of remaining gas reinjected	OK	0.00	0.00	[-]	1.0 if gas flooding applies (Note: Do not enter NA at all times
3.4.9 Fraction of water produced reinjected		1.00	1.00	[-]	1.0 if water flooding applies (Note: Do not enter NA at all tim
3.4.10 Fraction of steam generation via co-generation		0.00	0.00	[-]	

3.5 Processing practices

3.5.1 Heater/treater (1= Applicable; 0= Not applicable)		0	1	NA	
3.5.2 Stabilizer column (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.3 Application of AGR unit (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.4 Application of gas dehydration unit (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.5 Application of demethanizer unit (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.6 Ratio of flaring to oil production		182	82	scf/bbl	Default calculated based on satellite data from NOAA
3.5.7 Ratio of venting to oil production		0.0	0.0	scf/bbl	This is the ratio of venting used as a disposal mechanism (d
3.5.8 Volume fraction of diluent in diluted crude	OK	0.000	0.000	[-]	Default is the minimum indicated by the model inputs

3.6 Land use impacts

User Inputs and Results - Barge Scenario

3.6.1 Crude ecosystem carbon richness				
3.6.1.1 Low carbon richness (semi-arid grasslands)	0	0	NA	
3.6.1.2 Moderate carbon richness (mixed)	0	1	NA	
3.6.1.3 High carbon richness (forested)	1	0	NA	
3.6.2 Field development intensity				
3.6.2.1 Low intensity development and low oxidation	0	0	NA	
3.6.2.2 Moderate intensity development and moderate oxidation	0	1	NA	
3.6.2.3 High intensity development and high oxidation	1	0	NA	
3.7 Non-integrated upgrader (1= Applicable; 0= Not applicable)	0	0	NA	
3.8 Crude oil transport				
3.8.1 Fraction of oil transported by each mode				The total fraction of all modes may exceed 1.0 because mor
3.8.1.1 Ocean tanker	0	1	[-]	
3.8.1.2 Barge	1	0	[-]	
3.8.1.3 Pipeline	0	1	[-]	
3.8.1.4 Rail	1	0	[-]	
3.8.2 Transport distance (one way)				
3.8.2.1 Ocean tanker	0	5082	Miles	
3.8.2.2 Barge	2200	500	Miles	
3.8.2.3 Pipeline	1985	750	Miles	
3.8.2.4 Rail	1133	800	Miles	
3.8.3 Ocean tanker size, if applicable	250000	250000	Tons	
3.9 Small sources emissions	0.5	0.5	gCO_2 eq/MJ	Assumption to account for numerous small sources not inclu

Status

3.10 Overall error check	OK	Error check	For specific error checks see section 7 below

4 User inputs - Bitumen

Notes:
Change user inputs in Bitumen Extraction & Upgrading sheet.
Change crude production method in Drilling & Development sheet (section 2.1.3).

5 Summary results - Conventional

These results are derived from calculations in following sheets

	Value	Unit	Notes
5.1 Exploration			
5.1.1 Total energy consumption	0.000	MJ/MJ	Exploration energy use is not included in the current version of the model
5.1.2 Total GHG emissions	0.00	gCO_2eq/MJ	Exploration emissions are not included in the current version of the model
5.1.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
5.1.2.2 VFF	0.00	gCO_2eq/MJ	
5.2 Drilling & Development			
5.2.1 Total energy consumption	0.000	MJ/MJ	
5.2.2 Total GHG emissions	0.00	gCO_2eq/MJ	
5.2.2.1 Combustion/land use	0.00	gCO_2eq/MJ	

User Inputs and Results - Barge Scenario

5.2.2.2	VFF	0.00	gCO_2eq/MJ	
5.3	Crude production & extraction			
5.3.1	Total energy consumption	0.000	MJ/MJ	
5.3.2	Total GHG emissions	0.00	gCO_2eq/MJ	MJ of crude output
5.3.2.1	Combustion/land use	0.00	gCO_2eq/MJ	
5.3.2.2	VFF	0.00	gCO_2eq/MJ	
5.4	Surface processing			
5.4.1	Total energy consumption	0.000	MJ/MJ	
5.4.2	Total GHG emissions	0.00	gCO_2eq/MJ	MJ of crude output
5.4.2.1	Combustion/land use	0.00	gCO_2eq/MJ	
5.4.2.2	VFF	0.00	gCO_2eq/MJ	
5.5	Maintenance			
5.5.1	Total energy consumption	0.000	MJ/MJ	
5.5.2	Total GHG emissions	0.00	gCO_2eq/MJ	MJ of crude output
5.5.2.1	Combustion/land use	0.00	gCO_2eq/MJ	
5.5.2.2	VFF	0.00	gCO_2eq/MJ	
5.6	Waste disposal			
5.6.1	Total energy consumption	0.000	MJ/MJ	Waste disposal energy use is not included in the current version of the model
5.6.2	Total GHG emissions	0.00	gCO_2eq/MJ	Waste disposal emissions are not included in the current version of the model
5.6.2.1	Combustion/land use	0.00	gCO_2eq/MJ	
5.6.2.2	VFF	0.00	gCO_2eq/MJ	
5.7	Diluent			
5.7.1	Total energy consumption	0.000	MJ/MJ	
5.7.2	Total GHG emissions	0.00	gCO_2eq/MJ	
5.8	Non-integrated upgrader			
5.8.1	Total energy consumption	0.000	MJ/MJ	
5.8.2	Total GHG emissions	0.00	gCO_2eq/MJ	MJ of SCO
5.9	Crude transport			
5.9.1	Total energy consumption	0.000	MJ/MJ	
5.9.2	Total GHG emissions	0.00	gCO_2eq/MJ	MJ of crude transported
5.9.3	Loss factor	0.0000	NA	Calculated from crude oil losses
5.10	Other small sources	0.00	gCO_2eq/MJ	See sheet "Model Organization" for list of all sources not explicitly modeled in OPGEE. These sources are included her
5.11	Offsite emissions credit/debit	0.00	gCO_2eq/MJ	Credits (negative emissions) from fuels export + debts (positive emissions) from fuels import
5.12	Lifecycle energy consumption	0.00	MJ/MJ	
5.13	Lifecycle GHG emissions	0.00	gCO_2eq/MJ	MJ of crude at refinery gate

6 Summary result - Bitumen

These results are derived from calculations in Bitumen Extraction & Upgrading sheet.

		Value	Unit	Notes
6.1	Exploration			
6.1.1	Total energy consumption	0.000	MJ/MJ	Exploration energy use is not included in the current version of the model

User Inputs and Results - Barge Scenario

6.1.2	Total GHG emissions	0.00	gCO_2eq/MJ	Exploration emissions are not included in the current version of the model
6.1.2.1	Combustion/land use	0.00	gCO_2eq/MJ	
6.1.2.2	VFF	0.00	gCO_2eq/MJ	
6.2	Drilling & Development			
6.2.1	Total energy consumption	0.000	MJ/MJ	Energy use and emissions from mine preparation are included in bitumen extraction figures
6.2.2	Total GHG emissions	6.47	gCO_2eq/MJ	
6.2.2.1	Combustion/land use	6.47	gCO_2eq/MJ	
6.2.2.2	VFF	0.00	gCO_2eq/MJ	
6.3	Bitumen extraction			
6.3.1	Total energy consumption	0.252	MJ/MJ	
6.3.2	Total GHG emissions	14.61	gCO_2eq/MJ	MJ of bitumen output
6.3.2.1	Combustion/land use	11.30	gCO_2eq/MJ	
6.3.2.2	VFF	3.30	gCO_2eq/MJ	
6.4	Upgrading			
6.4.1	Total energy consumption	0.000	MJ/MJ	
6.4.2	Total GHG emissions	0.00	gCO_2eq/MJ	MJ of bitumen output
6.4.2.1	Combustion/land use	0.00	gCO_2eq/MJ	
6.4.2.2	VFF	0.00	gCO_2eq/MJ	
6.5	Maintenance			
6.5.1	Total energy consumption	0.000	MJ/MJ	
6.5.2	Total GHG emissions	0.00	gCO_2eq/MJ	MJ of bitumen output
6.5.2.1	Combustion/land use	0.00	gCO_2eq/MJ	
6.5.2.2	VFF	0.00	gCO_2eq/MJ	
6.6	Waste disposal			
6.6.1	Total energy consumption	0.000	MJ/MJ	Waste disposal energy use is not included in the current version of the model
6.6.2	Total GHG emissions	0.00	gCO_2eq/MJ	Waste disposal emissions are not included in the current version of the model
6.6.2.1	Combustion/land use	0.00	gCO_2eq/MJ	
6.6.2.2	VFF	0.00	gCO_2eq/MJ	
6.7	Crude transport			
6.7.1	Total energy consumption	0.058	MJ/MJ	
6.7.2	Total GHG emissions	4.61	gCO_2eq/MJ	MJ of crude transported
6.7.3	Loss factor	1.0001	NA	Calculated from crude oil losses
6.8	Other small sources	0.50	gCO_2eq/MJ	
6.9	Offsite emissions credit/debit	5.04		Credits (negative emissions) from fuels export + debts (positive emissions) from fuels import
6.10	Lifecycle energy consumption	0.31	MJ/MJ	
6.11	Lifecycle GHG emissions	31.23	gCO_2eq/MJ	MJ of crude at refinery gate

7 Error check

	Sheet	Cell	Status	Notes
7.1 Specific error checks				

User Inputs and Results - Barge Scenario

7.1.1	Production methods	User Inputs & Results	I61	OK
7.1.2	Water injection ratio	User Inputs & Results	I92	OK
7.1.3	Gas injection volume	User Inputs & Results	I93	OK
7.1.4	N2 injection ratio	User Inputs & Results	I94	OK
7.1.5	Steam-to-oil ratio (SOR)	User Inputs & Results	I95	OK
7.1.6	Field location	User Inputs & Results	I66	OK
7.1.7	Volume fraction of diluent	User Inputs & Results	I109	OK
7.1.8	Crude production method	Drilling & Development	M43	OK
7.1.9	Crude ecosystem carbon richness	Drilling & Development	M48	OK
7.1.10	Field development intensity	Drilling & Development	M53	OK
7.1.11	Gas composition	Production & Extraction	M45	OK
7.1.12	Fraction of gas to reinjection	Production & Extraction	L49	OK
7.1.13	Fraction of water to reinjection	Production & Extraction	L56	OK
7.1.14	Number of producing wells	Production & Extraction	L64	OK
7.1.15	Productivity index	Production & Extraction	L66	OK
7.1.16	Ratio of specific heats	Production & Extraction	L203	OK
7.1.17	NGL use	Surface Processing	L122	OK
7.1.18	Stage 1 water treatment	Surface Processing	L131	OK
7.1.19	Stage 2 water treatment	Surface Processing	L134	OK
7.1.20	Stage 3 water treatment	Surface Processing	L143	OK
7.1.21	Stage 4 water treatment	Surface Processing	L151	OK
7.1.22	Lift gas volume	Gas Balance	AP19	OK
7.1.23	Remaining gas volume	Gas Balance	AP28	OK
7.1.24	Steam injection	Steam Injection	M65	OK
7.1.25	Offsite electricity fuel mix	Electricity	C48 & C63	OK
7.1.26	Remainig gas > Fuel gas demand	Gas Balance	AR26	OK

Drilling and Development - Barge Scenario

Estimation of GHG emissions from drilling and field development

1 Drilling combustion emissions

1.1 Field drilling and development properties	User	Default	Units	User reference	Default reference
1.1.1 Crude location	Canada	USA			
1.1.2 Crude name	WCSB	Generic			
1.1.3 Field depth	550	7240	ft	Imperial Aspen Project	
1.1.4 API gravity	8	30		Default Bitumen	
1.1.5 Crude oil heating value	6.10	5.51	MMBtu LHV/bbl		
1.2. Drilling energy consumption during field development					
1.2.1 Energy intensity of drilling	2	1	NA		
1= Low intensity drilling					
2= High intensity drilling					
1.2.2 Energy intensity of drilling	103.9	104.5	MMBtu/1000 ft		
1.2.3 Energy intensity per well	57.2	756.7	MMBtu/well		
1.3. Per-well lifetime productivity					
1.3.1 Expected lifetime well productivity	547500	130000	bbl/well	100 bpd, 15 years	
1.3.1.1. Expected lifetime energy production	3340254	716898	MMBtu/well		
1.4. Fractional energy consumption per well drilled	0.0000	0.0011	MMBtu/MMBtu		

2 Land use impacts

2.1 Crude development properties	User	Default	Units	User reference	Default reference
2.1.1 Crude location	Canada	Generic			
2.1.2 Crude name	WCSB	Generic			
2.1.3 Crude production method					
2.1.3.1 Conventional, in situ production via wellbore	1	1	NA		
2.1.3.2 Mining-based production	0	0	NA		
Check:	OK	OK			
2.1.4 Crude ecosystem carbon richness					
2.1.4.1 Low carbon richness (semi-arid grasslands)	0	0	NA		Yeh et al. (2010)
2.1.4.2 Moderate carbon richness (mixed)	0	1	NA		Yeh et al. (2010)
2.1.4.3 High carbon richness (forested)	1	0	NA	Boreal Forest	Yeh et al. (2010)
Check:	OK	OK			
2.1.5 Field development intensity					
2.1.5.1 Low intensity development and low oxidation	0	0	NA		Yeh et al. (2010)
2.1.5.2 Moderate intensity development and moderate oxidation	0	1	NA		Yeh et al. (2010)
2.1.5.3 High intensity development and high oxidation	1	0	NA		Yeh et al. (2010)
Check:	OK	OK			
2.1.6 Timeframe of land use analysis (1 = 30 years, 2 = 150 years)	1	1			
Emissions code:	9	5			

Drilling and Development - Barge Scenario

Estimation of GHG emissions from drilling and field development

2.2 Source-specific land use emissions				
2.2.1 Soil carbon emissions	3.51	0.57	gCO$_2$eq/MJ	Yeh et al. (2010)
2.2.2 Biomass carbon emissions	2.94	0.68	gCO$_2$eq/MJ	Yeh et al. (2010)
2.2.3 Foregone sequestration emissions	0.02	0.01	gCO$_2$eq/MJ	Yeh et al. (2010)
2.3 Total land use emissions	6.5	1.3	gCO$_2$eq/MJ	

Crude Transport - Barge Scenario

Calculation of GHG emissions from crude oil transportation to refinery
Based on CA-GREET model

1 Results

		Value	Units
1.1	Total energy consumption	0.06	MJ/MJ
1.2	Total GHG emissions	4.61	gCO_2eq/MJ

2 Input assumptions and data

Table 2.1: Cargo Payload By Transportation Mode and by Product Fuel Type: Tons

Fuel Transported	Crude Oil
Ocean Tanker	250000
Barge	22500

Table 2.2: Horsepower Requirements for Ocean Tanker and Barges: Calculated with Cargo Capacity (unit is in HP)

	Crude Oil
Ocean Tank	34320.0
Barge	5600.0

Table 2.3: Energy Consumption for Ocean Tanker and Barge

	Ocean Tanker	Barge
Average Speed (Miles/Hour)	18.5	5.0
Trip from Product Origin to Destination		
Load Factor	80.0%	80.0%
Energy Consumption: Btu/hp-hr	4620	10119
Trip from Product Destination Back to Origin		
Load Factor	70.0%	60.0%
Energy Consumption: Btu/hp-hr	4691	10284

Notes: The load factor is the percentage of installed horsepower that is used for the trip

Table 2.4: Energy Intensity of Rail Transportation: Btu/ton-mile

Trip	Intensity
Trip from Product Origin to Destination	370
Trip from Product Destination Back to C	370

Table 2.5: Energy Intensity of Pipeline Transportation: Btu/ton-mile

	Turbine	Reciprocating Engine: Current	Reciprocating Engine: Future
Crude Pipeli	240	270	260

Table 2.6: Share of Power Generation Technologies for Pipeline Compression Stations

	Turbine	Reciprocating Engine: Current	Reciprocating Engine: Future
Crude Pipeli	55.0%	36.0%	9.0%

Crude Transport - Barge Scenario

Calculation of GHG emissions from crude oil transportation to refinery
Based on CA-GREET model

Table 2.7: Energy Consumption and Emissions of Feedstock Transportation

Feedstock	Crude Oil			
Transportation Mode	Tanker	Barge	Pipeline	Rail
Distance (Miles, one-way) - Default	5082	500	750	800
Distance (Miles, one-way)	0	2200	1985	1133
Share of Fuel Type Used:				
Diesel	0	0	0.45	1
Residual Oil	1	1	NA	NA
Natural Gas	0	0	0.55	NA
Electricity	NA	NA	NA	NA
Energy Intensity: Btu/ton-mile				
Origin to Destination	27.4	402.9	252.6	370.0
Back-Haul	24.3	307.1		
Total Energy consumption: Btu/MMBtu-	1.5	20.7	7.4	10.8
Total Emissions: grams/MMBtu-mile fuel transported				
VOC (incl. VOC from bulk term	0.000	0.001	0.000	0.001
CO	0.000	0.005	0.002	0.002
CH4 (incl. fugitive)	0.000	0.000	0.000	0.000
N2O	0.000	0.000	0.000	0.000
CO2	0.127	1.751	0.496	0.837
GHG	0.129	1.773	0.506	0.851

Table 2.8: Percentage of Fuel Transported by a Given Mode

Mode	Percent
Ocean tanker	0.0%
Barge	100.0%
Pipeline	0.0%
Rail	100.0%

Notes:
The shares here are for each mode traveled by the distance assumed above.
The total percentage of all modes may exceed 100% for some feedstocks or fuels because more than one transportation legs may be involved for transporting the feedst

Table 2.9: Feed losses: Btu/MMBtu fuel transported

Feed loss	62

3 Calculations

		Value	Unit
3.1	Crude transport energy consumption	57783.0	Btu/MMBtu
3.2	Crude transport GHG emissions	4865.2	gCO2eq/MMBtu

Bitumen Extraction and Upgrading - Barge Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

1 Results

	User	Units	User reference	Default reference
1.1 Total energy consumption	0.25	MJ/MJ		
1.1.1 Total energy consumption primary extraction	0.25	MJ/MJ		
1.1.1.1 Direct energy consumption primary extraction	0.20	MJ/MJ		
1.1.1.2 Indirect energy consumption primary extraction	0.05	MJ/MJ		
1.1.2 Total energy consumption upgrading	0.00	MJ/MJ		
1.1.2.1 Direct energy consumption upgrading	0.00	MJ/MJ		
1.1.2.2 Indirect energy consumption upgrading	0.00	MJ/MJ		
1.2 Total GHG emissions (excluding VFF)	16.34	gCO$_2$eq/MJ		
1.2.1 Primary extraction total GHG emissions - combustion emissions	16.34	gCO$_2$eq/MJ		
1.2.1.1 Direct emissions primary extraction	11.30	gCO$_2$eq/MJ		
1.2.1.2 Indirect emissions primary extraction	5.04	gCO$_2$eq/MJ		
1.2.2 Primary extraction - VFF emissions	3.30	gCO$_2$eq/MJ		
1.2.2 Upgrading - combustion emissions	0.00	gCO$_2$eq/MJ		
1.2.2.1 Direct emissions upgrading	0.00	gCO$_2$eq/MJ		
1.2.2.2 Indirect emissions upgrading	0.00	gCO$_2$eq/MJ		

2 Input assumptions and data

	User	Default	Units	User reference	Default reference
2.1 Crude or SCO name	WCSB	Generic			
2.2 Crude bitumen properties					
2.2.1 Crude bitumen API gravity	8	8	deg. API		GHGenius 4.0c
2.2.2 Crude bitumen specific gravity	1.01	1.01	sg		
2.2.3 Crude bitumen heating value	6.10	6.1	MMBtu/bbl (LHV)		
2.3 Synthetic crude oil (SCO) properties					
2.3.1 SCO API gravity	32	32	deg. API		www.crudemonitor.ca
2.3.2 SCO specific gravity	0.87	0.87	sg		
2.3.3 SCO heating value	5.47	5.47	MMBtu/bbl (LHV)		
2.4 Diluent properties					
2.4.1 Diluent API gravity	59.37	59.37	deg. API		
2.4.2 Diluent specific gravity	0.74	0.74	sg		
2.4.3 Diluent heating value	5.39	5.39	MMBtu/bbl (LHV)		
2.5 Oil production rate (choose bitumen output or SCO below)	830000	1500	STB/d		
	5.06E+09	8.20E+06	Mbtu LHV/d		
	5.34E+09	8.65E+06	MJ/d		
2.6 Project pathway choices					
2.6.1 Upgrading or blending					
2.6.1.1 Hydrocarbon upgraded - Produce SCO	0	1	NA		
2.6.1.2 Hydrocarbon not upgraded - Produce bitumen for dilution	1	0	NA		
Check:	OK	OK			
2.6.2 Primary extraction methodology					

Bitumen Extraction and Upgrading - Barge Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

2.6.2.1	Mining integrated		0	1	NA	
2.6.2.2	Mining non-integrated		0	0	NA	
2.6.2.3	In situ - Non-thermal production (primary)		0	0	NA	
2.6.2.4	In situ - Steam assisted gravity drainage (SAGD)		1	0	NA	
2.6.2.5	In situ - Cyclic steam stimulation (CSS)		0	0	NA	
		Check:	OK	OK		
2.7	In situ steam oil ratio (SOR)					
2.7.1	Steam assisted gravity drainage (SAGD) SOR		3.0	3.0	bbl steam/bbl bitumen	GHGenius 4.0c, (S&T
2.7.2	Cyclic steam stimulation (CSS) SOR		3.9	3.9	bbl steam/bbl bitumen	GHGenius 4.0c, (S&T
2.8	Diluent blending					
2.8.1	Volume fraction of dilbit as diluent		0.15	0.25	bbl diluent/bbl dilbit	
2.8.2	Volume fraction of dilbit as bitumen		0.85	0.75	bbl bitumen/bbl dilbit	
2.8.3	Dilbit heating value		5.99	5.92	MMBtu/bbl dilbit	
2.9	Fuels imported for extraction (or recorded as net imports)					
2.9.1	Diesel fuel		0	0		
2.9.2	Natural gas		1	1		
2.9.3	Electricity		1	1		
2.9.4	Coke		0	0		
2.9.5	Still Gas		0	0		
2.9.6	Diluent		1	1		
2.10	Fuels imported for upgrading (or recorded as net imports)					
2.9.1	Diesel fuel		0	0		
2.9.2	Natural gas		1	1		
2.9.3	Electricity		1	1		
2.9.4	Coke		0	0		
2.9.5	Still Gas		0	0		
2.11	Associated gas composition	N_2	2.00	2.00	mol%	
		CO_2	6.00	6.00	mol%	
		C_1	84.00	84.00	mol%	
		C_2	4.00	4.00	mol%	
		C_3	2.00	2.00	mol%	
		C_4+	1.00	1.00	mol%	
		H_2S	1.00	1.00	mol%	
2.12	Land use impact inputs					
2.12.1	Crude ecosystem carbon richness					
1=	Low carbon richness (semi-arid grasslands)		0	0	NA	Yeh et al. (2010)
2=	Moderate carbon richness (mixed)		0	1	NA	Yeh et al. (2010)
3=	High carbon richness (forested)		1	0	NA	Yeh et al. (2010)
		Check:	OK	OK		
2.12.2	Field development intensity					
1=	Low intensity development and low oxidation		0	0	NA	Yeh et al. (2010)
2=	Moderate intensity development and moderate oxidation		0	1	NA	Yeh et al. (2010)
3=	High intensity development and high oxidation		1	0	NA	Yeh et al. (2010)
		Check:	OK	OK		

Bitumen Extraction and Upgrading - Barge Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Emissions code: 9 11

3 Calculations

3.1 Direct energy consumption		User	Units
3.1.1 Energy consumed primary extraction (in situ and mining, includes mining for integrated mining & upgrading)			
3.1.1.1 Diesel fuel		0.00	MMBtu/bbl dilbit
3.1.1.2 Natural gas	1.196273	1.20	MMBtu/bbl dilbit
3.1.1.3 Electricity		0.03	MMBtu/bbl dilbit
3.1.1.4 Coke		0.00	MMBtu/bbl dilbit
3.1.1.5 Still Gas		0.00	MMBtu/bbl dilbit
3.1.2 Energy consumed upgrading (includes upgrading for integrated mining & upgrading)			
3.1.2.1 Diesel fuel		0.00	MMBtu/bbl dilbit
3.1.2.2 Natural gas		0.00	MMBtu/bbl dilbit
3.1.2.3 Electricity		0.00	MMBtu/bbl dilbit
3.1.2.4 Coke		0.00	MMBtu/bbl dilbit
3.1.2.5 Still Gas		0.00	MMBtu/bbl dilbit
3.1.3 Direct energy consumed (net, extraction + upgrading)			
3.1.3.1 Diesel fuel		0.000	MMBtu/bbl dilbit
3.1.3.2 Natural gas		1.196	MMBtu/bbl dilbit
3.1.3.3 Electricity		0.030	MMBtu/bbl dilbit
3.1.3.4 Coke		0.000	MMBtu/bbl dilbit
3.1.3.5 Still Gas		0.000	MMBtu/bbl dilbit
3.2 Fugitive emissions, venting, and flaring			
3.2.1 Gas released via fugitive emissions and direct venting		36.3	scf/bbl dilbit
3.2.1.1 Fugitive emissions GWP weighted		15129	gCO2eq./bbl dilbit
3.2.2 Gas consumed in flares		77	scf/bbl dilbit
3.2.1.1 Gas flared - Combustion products GWP weighted		4159.3	gCO2eq./bbl dilbit
3.2.1.2 Gas flared - Slippage products GWP weighted		1594.4	gCO2eq./bbl dilbit
3.3 Energy imports (net imports for computing upstream fuel cycle emissions)			
3.3.1 Energy imports primary extraction (in situ and mining, includes mining for integrated mining & upgrading)			
3.3.1.1 Diesel fuel		0.00	MMBtu/bbl dilbit
3.3.1.2 Natural gas		1.20	MMBtu/bbl dilbit
3.3.1.3 Electricity		0.03	MMBtu/bbl dilbit
3.3.1.4 Coke		0.00	MMBtu/bbl dilbit
3.3.1.5 Still Gas		0.00	MMBtu/bbl dilbit
3.3.1.6 Diluent		0.81	MMBtu/bbl dilbit
3.3.2 Energy imports upgrading (includes upgrading for integrated mining & upgrading)			
3.3.2.1 Diesel fuel		0.00	MMBtu/bbl dilbit
3.3.2.2 Natural gas		0.00	MMBtu/bbl dilbit
3.3.2.3 Electricity		0.00	MMBtu/bbl dilbit
3.3.2.4 Coke		0.00	MMBtu/bbl dilbit
3.3.2.5 Still Gas		0.00	MMBtu/bbl dilbit
3.4 Total energy consumption			
3.4.1 Direct energy consumption			
3.4.1.1 Primary extraction		1.23	MMBtu/bbl dilbit

Bitumen Extraction and Upgrading - Barge Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

3.4.1.2 Upgrading	0.00	MMBtu/bbl dilbit	
3.4.2 Indirect energy consumption			
3.4.2.1 Primary extraction	0.29	MMBtu/bbl dilbit	
3.4.2.2 Upgrading	0.00	MMBtu/bbl dilbit	
3.5 Land use GHGs			
3.5.1 Soil carbon emissions	3.5	g/MJ dilbit	Yeh et al. (2010)
3.5.2 Biomass carbon emissions	2.9	g/MJ dilbit	Yeh et al. (2010)
3.5.3 Foregone sequestration emissions	0.0	g/MJ dilbit	Yeh et al. (2010)
3.5.4 Total land use emissions	6.5	g/MJ dilbit	
3.6 Total GHG emissions			
3.5.1 Direct GHG emissions			
3.5.1.1 Primary extraction	71496	g/bbl dilbit	
3.5.1.2 Upgrading	0	g/bbl dilbit	
3.5.2 Indirect GHG emissions			
3.5.2.1 Primary extraction	31864	g/bbl dilbit	
3.5.2.2 Upgrading	0	g/bbl dilbit	

4 Data tables

Table 4.1: Energy demand for primary bitumen extraction
Volumetric and mass units

	Primary	SAGD	CSS	Mining	
Diesel fuel	6	0	0	35	L diesel/m3 bitumen
Natural gas	130	255	270	73	m3/m3 bitumen
Electricity	115	65	55	-70	kWh/m3 bitumen
Coke	0	0	0	0	kg/m3 bitumen
Still Gas	0	0	0	0	m3/m3 bitumen

Source: GHGenius v 4.03a, 'Crude Production' D293-G301 for different selected production techniques.
Data quality for primary production is poor. O'Connor models primary production between heavy oil production and SAGD based on a consultancy study (GHGenius oil production update, March 2011, p. 41)

Table 4.2: Energy demand for primary bitumen extraction
Volumetric and mass units

	Primary	SAGD	CSS	Mining	
Diesel fuel	0.030	0.000	0.000	0.189	MMBtu LHV/bbl bitumen
Natural gas	0.717	1.407	1.490	0.405	MMBtu LHV/bbl bitumen
Electricity	0.062	0.035	0.030	-0.038	MMBtu LHV/bbl bitumen
Coke	0.000	0.000	0.000	0.000	MMBtu LHV/bbl bitumen
Still Gas	0.000	0.000	0.000	0.000	MMBtu LHV/bbl bitumen

Bitumen Extraction and Upgrading - Barge Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Table 4.3: Energy demand for upgrading
Energy units (MJ LHV/tonne SCO)

	Stand-alone upgrader	Integrated mining & upgrading	Units
Diesel fuel		565	MJ LHV/tonne SCO
Natural gas	4736	4612	MJ LHV/tonne SCO
Electricity	217	-100	MJ LHV/tonne SCO
Coke	1278	1573	MJ LHV/tonne SCO
Still Gas	4208	3115	MJ LHV/tonne SCO

Source: GHGenius v 4.03a, 'Crude Production' L292-N301, converted from reported GHGenius HHVs to LHVs using GHGenius HHV/LHV ratios from "Fuel Char" sheet column R
Notes: GHGenius assumes a 1:1 mass ratio for bitumen to SCO production for stand-alone operations.
The density of SCO assumed in GHGenius is not clear, so we assume 32 API as in Suncor Synthetic A synthetic crude oil
We assume that fugitives are same as above for mining operations, but that integrated upgrading adds the remainder as flare emissions.

Table 4.4: Energy demand for upgrading
Energy units (MMBtu/bbl SCO)

	Stand-alone upgrader	Integrated mining & upgrading	Units
Diesel fuel	0.000	0.074	MMBtu LHV/bbl SCO
Natural gas	0.618	0.601	MMBtu LHV/bbl SCO
Electricity	0.028	-0.013	MMBtu LHV/bbl SCO
Coke	0.167	0.205	MMBtu LHV/bbl SCO
Still Gas	0.549	0.406	MMBtu LHV/bbl SCO

Table 4.5: Steam injection rates for in situ projects

	SOR	Units
CSS	3.9	bbl steam/bbl bitumen
SAGD	3.0	bbl steam/bbl bitumen

GHGenius 4.0c, (S&T)^2, March 2011 Update of oil production and refining in GHGenius, p. 40-44

Table 4.6: Volumetric gain upon conversion to SCO

	Gain	Units

Bitumen Extraction and Upgrading - Barge Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Integrated upgrading gain	0.9	m^3 SCO/m^3 bitumen
Stand alone upgrading gain	1.2	m^3 SCO/m^3 bitumen

Notes:

GHGenius assumes a 1:1 mass ratio for bitumen to SCO production for stand-alone operations.

GHGenius assumes a 1.25:1 mass ratio for bitumen to SCO production for integrated upgraders (coking based rather than via hydrogen addition as in stand-alone Scotford upgrader)

Table 4.7: Diluent composition

Diluent type	Density	API gravity	C1-C3	C4	C5	C6	C7	C8	C9	C10	C11	C12	C12+	C	H	Mass C	Mass H	Mass Frac C
CRW-675	727.20	62.90	0.00	0.05	0.30	0.21	0.16	0.09	0.05	0.03	0.02	0.01	0.07	6.90	15.79	82.75	15.79	0.84
CPC 475 PetroCanada condensate (	757.20	55.20	0.00	0.00	0.00	0.07	0.35	0.34	0.17	0.05	0.01	0.00	0.00	7.83	17.66	93.94	17.66	0.84
CPR 0822 Peace condensate (2006)	739.60	59.60	0.01	0.07	0.22	0.21	0.17	0.10	0.05	0.03	0.03	0.02	0.08	7.18	16.36	86.18	16.36	0.84

Assumed species	C_3H_8	C_4H_{10}	C_5H_{12}	C_6H_{14}	C_7H_{16}	C_8H_{18}	C_9H_{20}	$C_{10}H_{22}$	$C_{11}H_{24}$	$C_{12}H_{26}$	$C_{14}H_{30}$
C	3	4	5	6	7	8	9	10	11	12	14
H	8	10	12	14	16	18	20	22	24	26	30

Notes:

Source: Analysis of Blending Data used in Condensate EQ model. Prepared for Canadian Association of Petroleum Producers (CAPP) by Advantage Insight Group Inc. January 2007

C5 contains normal and iso-pentane, as well as cyclopentane

C6 contains Benzene and methylcyclopentane as well as cyclohexane

C7 contains heptanes as well as toluene and methylcyclohexane

C8 contains octanes plus xylenes

C9 contains nonanes as well as 1,2,4 trimethybenzene

For simplicity, assume parafinic HCs

Dulong formula is used to approximate the heating value of the condensate/diluent

Table 4.8: Other dilbit properties

Property	Value	Unit
Dilbit blending energy	0.00	MMBtu/bbl
Diluent embodied energy	0.11	MMBtu/MMBtu diluent
Diluent embodied emissions	8175.25	g/MMBtu diluent

Notes:

Assume blending dilbit has negligible energy cost

Assume diluent has identical embodied energy and emissions as natural gas

Table 4.9: Flaring emissions from bitumen extraction operations

	Primary	SAGD	CSS	Mining	
Flaring emissions	0.00009	0.00009	0.00009	0.00009	MMscf/bbl
Flaring emissions	90.0	90.0	90.0	90.0	scf/bbl

Values for flaring emissions from NOAA satellite observations for average Canadian crude production, for consistency with other flaring datasets and due to its verifiable data source.

Bitumen Extraction and Upgrading - Barge Scenario

Mass Frac H	HHV		LHV		HHV		LHV	
0.16	22196.06	Btu/lb	20797.04	Btu LHV/lb	5.66	MMBtu/bbl	5.30	MMBtu/bbl
0.16	22099.58	Btu/lb	20718.33	Btu LHV/lb	5.86	MMBtu/bbl	5.50	MMBtu/bbl
0.16	22163.89	Btu/lb	20770.79	Btu LHV/lb	5.74	MMBtu/bbl	5.38	MMBtu/bbl

Bitumen Extraction and Upgrading - Barge Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Table 4.10: Fugitive emissions from bitumen extraction operations

	Primary	SAGD	CSS	Mining	
Fugitive emissions	7500	7500	7500	5480	L/tonne bitumen
Fugitive emissions	42.7	42.7	42.7	31.2	scf/bbl

All mining emissions are fugitives, as these are mine face fugitive methane and methane from tailings ponds. See GHGenius 2011 report: Update of oil production and refining data in GHGenius, Tables 4-18 and 4-19.

All in situ emissions are fugitives from gathering and processing systems (batteries). See GHGenius 2011 report: Update of oil production and refining data in GHGenius, Figure 4-16 for 2009.

RAILCAR SCENARIO

User Inputs and Summary Results - Railcar Scenario

1 Summary results

Model error check: **OK**

Table 1.1: Summary GHG emissions

GHG emissions [gCO2eq/MJ]					
	WCSB				
Exploration	0.00				
Drilling	6.47				
Production	11.30				
Processing	0.00				
Upgrading	0.00				
Maintenance	0.00				
Waste	0.00				
VFF	3.30				
Diluent	0.00				
Misc.	0.50				
Transport	2.01				
Offsite emissions	5.04				
Net lifecycle emis	28.62				

Notes: Copy highlighted column and paste 'as numbers' to generate a record

Figure 1.1: Summary GHG emissions

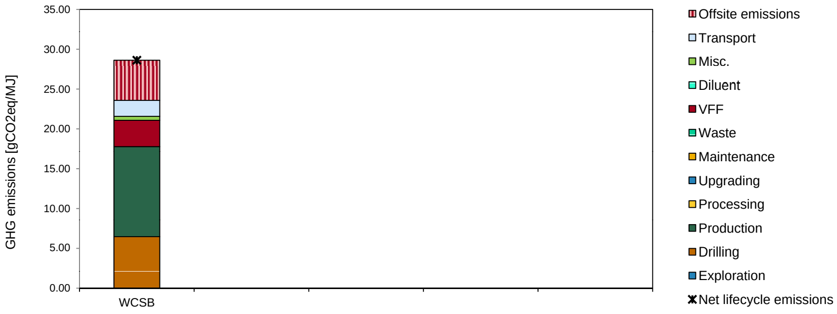
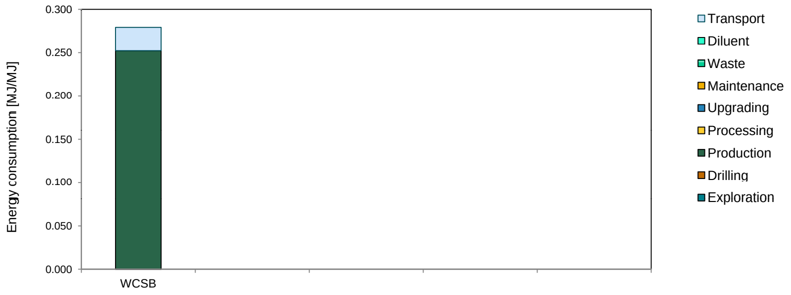


Table 1.2: Summary energy consumption

Energy consumption [MJ/MJ]					
	WCSB				
Exploration	0.00				
Drilling	0.00				
Production	0.25				
Processing	0.00				
Upgrading	0.00				
Maintenance	0.00				
Waste	0.00				
Diluent	0.00				
Transport	0.03				
Total	0.279				

Notes: Copy highlighted column and paste 'as numbers' to generate a record

Figure 1.2: Summary energy consumption



2 Petroleum resource

2.1 Conventional		0	1	NA
2.2 Bitumen		1	0	NA
	Check:	OK	OK	

User Inputs and Summary Results - Railcar Scenario

3 User inputs - Conventional

Enter primary input parameters and choices		User	Default	Unit	Notes
3.1 Production methods					
Note: Enter "1" where applicable and "0" where not applicable					
3.1.1 Downhole pump		1	1	NA	
3.1.2 Water reinjection		1	1	NA	If water flooding applies then "0"
3.1.3 Gas reinjection		1	1	NA	If gas flooding applies then "0"
3.1.4 Water flooding		0	0	NA	This is used for injecting amounts of water larger than the ar
3.1.5 Gas lifting	OK	0	0	NA	This is used for gas lifting
3.1.6 Gas flooding		0	0	NA	This is used for injecting a different type of gas (e.g. N2) or a
3.1.7 Steam flooding		0	0	NA	This is used for injecting steam
3.2 Field properties					
3.2.1 Field location (Country)	OK	Canada	Generic	NA	
3.2.2 Field name		WCSB	Generic	NA	
3.2.3 Field age		40	35	yr	
3.2.4 Field depth		550	7240	ft	
3.2.5 Oil production volume		830000	1500	bbl/d	
3.2.6 Number of producing wells		8300	4536	[-]	
3.2.7 Number of water injecting wells		8300	4416	[-]	
3.2.8 Well diameter		7.0	2.8	in	
3.2.9 Productivity index		3.0	3.0	bbl/psi-d	
3.2.10 Average reservoir pressure		1557	118	psi	Downhole pump on
3.3 Fluid properties					
3.3.1 API gravity of produced crude		8	30	deg. API	
3.3.2 Associated gas composition					
	N_2	2.00	2.0	mol%	Composition on dry basis
	CO_2	6.00	6.0	mol%	
	C_1	84.00	84.0	mol%	
	C_2	4.00	4.0	mol%	
	C_3	2.00	2.0	mol%	
	C_4+	1.00	1.0	mol%	
	H_2S	1.00	1.0	mol%	
	Sum				
3.4 Production practices					
Notes: Enter "NA" where not applicable					
3.4.1 Gas-to-oil ratio (GOR)		908	227	scf/bbl oil	In the case of gas lift, the gas oil ratio should include produc
3.4.2 Water-to-oil ratio (WOR)		4.3	5.5	bbl water/bbl oil	
3.4.3 Water injection ratio	OK	5.3	5.3	bbl water/bbl oil	
3.4.4 Gas lifting injection ratio	OK	1500	1500	scf/bbl liquid	Gas lifting injection (does not include gas reinjected into the
3.4.5 Gas flooding injection ratio	OK	1362	1362	scf/bbl oil	
3.4.6 Steam-to-oil ratio (SOR)	OK	3.0	3.0	bbl steam/bbl oil	
3.4.7 Fraction of required electricity generated onsite		0.00	0.00	[-]	
3.4.8 Fraction of remaining gas reinjected	OK	0.00	0.00	[-]	1.0 if gas flooding applies (Note: Do not enter NA at all times
3.4.9 Fraction of water produced reinjected		1.00	1.00	[-]	1.0 if water flooding applies (Note: Do not enter NA at all tim
3.4.10 Fraction of steam generation via co-generation		0.00	0.00	[-]	

User Inputs and Summary Results - Railcar Scenario

3.5 Processing practices					
3.5.1 Heater/treater (1= Applicable; 0= Not applicable)		0	1	NA	
3.5.2 Stabilizer column (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.3 Application of AGR unit (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.4 Application of gas dehydration unit (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.5 Application of demethanizer unit (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.6 Ratio of flaring to oil production		182	82	scf/bbl	Default calculated based on satellite data from NOAA
3.5.7 Ratio of venting to oil production		0.0	0.0	scf/bbl	This is the ratio of venting used as a disposal mechanism (d
3.5.8 Volume fraction of diluent in diluted crude	OK	0.000	0.000	[-]	Default is the minimum indicated by the model inputs
3.6 Land use impacts					
3.6.1 Crude ecosystem carbon richness					
3.6.1.1 Low carbon richness (semi-arid grasslands)		0	0	NA	
3.6.1.2 Moderate carbon richness (mixed)		0	1	NA	
3.6.1.3 High carbon richness (forested)		1	0	NA	
3.6.2 Field development intensity					
3.6.2.1 Low intensity development and low oxidation		0	0	NA	
3.6.2.2 Moderate intensity development and moderate oxidation		0	1	NA	
3.6.2.3 High intensity development and high oxidation		1	0	NA	
3.7 Non-integrated upgrader (1= Applicable; 0= Not applicable)		0	0	NA	
3.8 Crude oil transport					
3.8.1 Fraction of oil transported by each mode					The total fraction of all modes may exceed 1.0 because mor
3.8.1.1 Ocean tanker		0	1	[-]	
3.8.1.2 Barge		0	0	[-]	
3.8.1.3 Pipeline		0	1	[-]	
3.8.1.4 Rail		1	0	[-]	
3.8.2 Transport distance (one way)					
3.8.2.1 Ocean tanker		0	5082	Miles	
3.8.2.2 Barge		2200	500	Miles	
3.8.2.3 Pipeline		1985	750	Miles	
3.8.2.4 Rail		2485	800	Miles	
3.8.3 Ocean tanker size, if applicable		250000	250000	Tons	
3.9 Small sources emissions		0.5	0.5	gCO_2 eq/MJ	Assumption to account for numerous small sources not inclu

	Status		
3.10 Overall error check	OK	Error check	For specific error checks see section 7 below

4 User inputs - Bitumen

Notes:
Change user inputs in Bitumen Extraction & Upgrading sheet.
Change crude production method in Drilling & Development sheet (section 2.1.3).

User Inputs and Summary Results - Railcar Scenario

5 Summary results - Conventional

These results are derived from calculations in following sheets

	Value	Unit	Notes
5.1 Exploration			
5.1.1 Total energy consumption	0.000	MJ/MJ	Exploration energy use is not included in the current version of the model
5.1.2 Total GHG emissions	0.00	gCO_2eq/MJ	Exploration emissions are not included in the current version of the model
5.1.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
5.1.2.2 VFF	0.00	gCO_2eq/MJ	
5.2 Drilling & Development			
5.2.1 Total energy consumption	0.000	MJ/MJ	
5.2.2 Total GHG emissions	0.00	gCO_2eq/MJ	
5.2.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
5.2.2.2 VFF	0.00	gCO_2eq/MJ	
5.3 Crude production & extraction			
5.3.1 Total energy consumption	0.000	MJ/MJ	
5.3.2 Total GHG emissions	0.00	gCO_2eq/MJ	MJ of crude output
5.3.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
5.3.2.2 VFF	0.00	gCO_2eq/MJ	
5.4 Surface processing			
5.4.1 Total energy consumption	0.000	MJ/MJ	
5.4.2 Total GHG emissions	0.00	gCO_2eq/MJ	MJ of crude output
5.4.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
5.4.2.2 VFF	0.00	gCO_2eq/MJ	
5.5 Maintenance			
5.5.1 Total energy consumption	0.000	MJ/MJ	
5.5.2 Total GHG emissions	0.00	gCO_2eq/MJ	MJ of crude output
5.5.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
5.5.2.2 VFF	0.00	gCO_2eq/MJ	
5.6 Waste disposal			
5.6.1 Total energy consumption	0.000	MJ/MJ	Waste disposal energy use is not included in the current version of the model
5.6.2 Total GHG emissions	0.00	gCO_2eq/MJ	Waste disposal emissions are not included in the current version of the model
5.6.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
5.6.2.2 VFF	0.00	gCO_2eq/MJ	
5.7 Diluent			
5.7.1 Total energy consumption	0.000	MJ/MJ	
5.7.2 Total GHG emissions	0.00	gCO_2eq/MJ	
5.8 Non-integrated upgrader			
5.8.1 Total energy consumption	0.000	MJ/MJ	
5.8.2 Total GHG emissions	0.00	gCO_2eq/MJ	MJ of SCO
5.9 Crude transport			
5.9.1 Total energy consumption	0.000	MJ/MJ	
5.9.2 Total GHG emissions	0.00	gCO_2eq/MJ	MJ of crude transported
5.9.3 Loss factor	0.0000	NA	Calculated from crude oil losses

User Inputs and Summary Results - Railcar Scenario

5.10 Other small sources	0.00	gCO$_2$eq/MJ	See sheet "Model Organization" for list of all sources not explicitly modeled in OPGEE. These sources are included her
5.11 Offsite emissions credit/debit	0.00	gCO$_2$eq/MJ	Credits (negative emissions) from fuels export + debts (positive emissions) from fuels import
5.12 Lifecycle energy consumption	0.00	MJ/MJ	
5.13 Lifecycle GHG emissions	0.00	gCO$_2$eq/MJ	MJ of crude at refinery gate

6 Summary result - Bitumen

These results are derived from calculations in Bitumen Extraction & Upgrading sheet.

	Value	Unit	Notes
6.1 Exploration			
6.1.1 Total energy consumption	0.000	MJ/MJ	Exploration energy use is not included in the current version of the model
6.1.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	Exploration emissions are not included in the current version of the model
6.1.2.1 Combustion/land use	0.00	gCO$_2$eq/MJ	
6.1.2.2 VFF	0.00	gCO$_2$eq/MJ	
6.2 Drilling & Development			
6.2.1 Total energy consumption	0.000	MJ/MJ	Energy use and emissions from mine preparation are included in bitumen extraction figures
6.2.2 Total GHG emissions	6.47	gCO$_2$eq/MJ	
6.2.2.1 Combustion/land use	6.47	gCO$_2$eq/MJ	
6.2.2.2 VFF	0.00	gCO$_2$eq/MJ	
6.3 Bitumen extraction			
6.3.1 Total energy consumption	0.252	MJ/MJ	
6.3.2 Total GHG emissions	14.61	gCO$_2$eq/MJ	MJ of bitumen output
6.3.2.1 Combustion/land use	11.30	gCO$_2$eq/MJ	
6.3.2.2 VFF	3.30	gCO$_2$eq/MJ	
6.4 Upgrading			
6.4.1 Total energy consumption	0.000	MJ/MJ	
6.4.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	MJ of bitumen output
6.4.2.1 Combustion/land use	0.00	gCO$_2$eq/MJ	
6.4.2.2 VFF	0.00	gCO$_2$eq/MJ	
6.5 Maintenance			
6.5.1 Total energy consumption	0.000	MJ/MJ	
6.5.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	MJ of bitumen output
6.5.2.1 Combustion/land use	0.00	gCO$_2$eq/MJ	
6.5.2.2 VFF	0.00	gCO$_2$eq/MJ	
6.6 Waste disposal			
6.6.1 Total energy consumption	0.000	MJ/MJ	Waste disposal energy use is not included in the current version of the model
6.6.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	Waste disposal emissions are not included in the current version of the model
6.6.2.1 Combustion/land use	0.00	gCO$_2$eq/MJ	
6.6.2.2 VFF	0.00	gCO$_2$eq/MJ	

User Inputs and Summary Results - Railcar Scenario

6.7 Crude transport			
6.7.1 Total energy consumption	0.027	MJ/MJ	
6.7.2 Total GHG emissions	2.01	gCO_2eq/MJ	MJ of crude transported
6.7.3 Loss factor	1.0001	NA	Calculated from crude oil losses
6.8 Other small sources	0.50	gCO_2eq/MJ	
6.9 Offsite emissions credit/debit	5.04		Credits (negative emissions) from fuels export + debts (positive emissions) from fuels import
6.10 Lifecycle energy consumption	0.28	MJ/MJ	
6.11 Lifecycle GHG emissions	28.62	gCO_2eq/MJ	MJ of crude at refinery gate

7 Error check

	Sheet	Cell	Status	Notes
7.1 Specific error checks				
7.1.1 Production methods	User Inputs & Results	I61	OK	
7.1.2 Water injection ratio	User Inputs & Results	I92	OK	
7.1.3 Gas injection volume	User Inputs & Results	I93	OK	
7.1.4 N2 injection ratio	User Inputs & Results	I94	OK	
7.1.5 Steam-to-oil ratio (SOR)	User Inputs & Results	I95	OK	
7.1.6 Field location	User Inputs & Results	I66	OK	
7.1.7 Volume fraction of diluent	User Inputs & Results	I109	OK	
7.1.8 Crude production method	Drilling & Development	M43	OK	
7.1.9 Crude ecosystem carbon richness	Drilling & Development	M48	OK	
7.1.10 Field development intensity	Drilling & Development	M53	OK	
7.1.11 Gas composition	Production & Extraction	M45	OK	
7.1.12 Fraction of gas to reinjection	Production & Extraction	L49	OK	
7.1.13 Fraction of water to reinjection	Production & Extraction	L56	OK	
7.1.14 Number of producing wells	Production & Extraction	L64	OK	
7.1.15 Productivity index	Production & Extraction	L66	OK	
7.1.16 Ratio of specific heats	Production & Extraction	L203	OK	
7.1.17 NGL use	Surface Processing	L122	OK	
7.1.18 Stage 1 water treatment	Surface Processing	L131	OK	
7.1.19 Stage 2 water treatment	Surface Processing	L134	OK	
7.1.20 Stage 3 water treatment	Surface Processing	L143	OK	
7.1.21 Stage 4 water treatment	Surface Processing	L151	OK	
7.1.22 Lift gas volume	Gas Balance	AP19	OK	
7.1.23 Remaining gas volume	Gas Balance	AP28	OK	
7.1.24 Steam injection	Steam Injection	M65	OK	
7.1.25 Offsite electricity fuel mix	Electricity	C48 & C63	OK	
7.1.26 Remainig gas > Fuel gas demand	Gas Balance	AR26	OK	

Drilling and Development - Railcar Scenario

Estimation of GHG emissions from drilling and field development

1 Drilling combustion emissions

	User	Default	Units	User reference	Default reference
1.1 Field drilling and development properties					
1.1.1 Crude location	Canada	USA			
1.1.2 Crude name	WCSB	Generic			
1.1.3 Field depth	550	7240	ft	Imperial Aspen Project	
1.1.4 API gravity	8	30		Typical Oil Sand API	
1.1.5 Crude oil heating value	6.10	5.51	MMBtu LHV/bbl		
1.2. Drilling energy consumption during field development					
1.2.1 Energy intensity of drilling	2	1	NA		
1= Low intensity drilling					
2= High intensity drilling					
1.2.2 Energy intensity of drilling	103.9	104.5	MMBtu/1000 ft		
1.2.3 Energy intensity per well	57.2	756.7	MMBtu/well		
1.3. Per-well lifetime productivity					
1.3.1 Expected lifetime well productivity	547500	130000	bbl/well		
1.3.1.1. Expected lifetime energy production	3340254	716898	MMBtu/well		
1.4. Fractional energy consumption per well drilled	0.0000	0.0011	MMBtu/MMBtu		

2 Land use impacts

	User	Default	Units	User reference	Default reference
2.1 Crude development properties					
2.1.1 Crude location	Canada	Generic			
2.1.2 Crude name	WCSB	Generic			
2.1.3 Crude production method					
2.1.3.1 Conventional, in situ production via wellbore	1	1	NA		
2.1.3.2 Mining-based production	0	0	NA		
Check:	OK	OK			
2.1.4 Crude ecosystem carbon richness					
2.1.4.1 Low carbon richness (semi-arid grasslands)	0	0	NA		Yeh et al. (2010)
2.1.4.2 Moderate carbon richness (mixed)	0	1	NA		Yeh et al. (2010)
2.1.4.3 High carbon richness (forested)	1	0	NA	Boreal Forest	Yeh et al. (2010)
Check:	OK	OK			

Drilling and Development - Railcar Scenario

Estimation of GHG emissions from drilling and field development

2.1.5	Field development intensity				
2.1.5.1	Low intensity development and low oxidation	0	0	NA	Yeh et al. (2010)
2.1.5.2	Moderate intensity development and moderate oxidation	0	1	NA	Yeh et al. (2010)
2.1.5.3	High intensity development and high oxidation	1	0	NA	Yeh et al. (2010)
	Check:	OK	OK		
2.1.6	Timeframe of land use analysis (1 = 30 years, 2 = 150 years)	1	1		
	Emissions code:	9	5		
2.2	Source-specific land use emissions				
2.2.1	Soil carbon emissions	3.51	0.57	gCO_2eq/MJ	Yeh et al. (2010)
2.2.2	Biomass carbon emissions	2.94	0.68	gCO_2eq/MJ	Yeh et al. (2010)
2.2.3	Foregone sequestration emissions	0.02	0.01	gCO_2eq/MJ	Yeh et al. (2010)
2.3	Total land use emissions	6.5	1.3	gCO_2eq/MJ	

Crude Transport - Railcar Scenario

Calculation of GHG emissions from crude oil transportation to refinery
Based on CA-GREET model

1 Results

		Value	Units
1.1	Total energy consumption	0.03	MJ/MJ
1.2	Total GHG emissions	2.01	gCO_2eq/MJ

2 Input assumptions and data

Table 2.1: Cargo Payload By Transportation Mode and by Product Fuel Type: Tons

Fuel Transported	Crude Oil
Ocean Tanker	250000
Barge	22500

Table 2.2: Horsepower Requirements for Ocean Tanker and Barges: Calculated with Cargo Capacity (unit is in HP)

	Crude Oil
Ocean Tank	34320.0
Barge	5600.0

Table 2.3: Energy Consumption for Ocean Tanker and Barge

	Ocean Tanker	Barge
Average Speed (Miles/Hour)	18.5	5.0
Trip from Product Origin to Destination		
Load Factor	80.0%	80.0%
Energy Consumption: Btu/hp-hr	4620	10119
Trip from Product Destination Back to Origin		
Load Factor	70.0%	60.0%
Energy Consumption: Btu/hp-hr	4691	10284

Notes: The load factor is the percentage of installed horsepower that is used for the trip

Table 2.4: Energy Intensity of Rail Transportation: Btu/ton-mile

Trip	Intensity
Trip from Product Origin to Destination	370
Trip from Product Destination Back to	370

Table 2.5: Energy Intensity of Pipeline Transportation: Btu/ton-mile

	Turbine	Reciprocating Engine: Current	Reciprocating Engine: Future
Crude Pipeli	240	270	260

Table 2.6: Share of Power Generation Technologies for Pipeline Compression Stations

	Turbine	Reciprocating Engine: Current	Reciprocating Engine: Future
Crude Pipeli	55.0%	36.0%	9.0%

Crude Transport - Railcar Scenario

Calculation of GHG emissions from crude oil transportation to refinery
Based on CA-GREET model

Table 2.7: Energy Consumption and Emissions of Feedstock Transportation

Feedstock	Crude Oil			
Transportation Mode	Tanker	Barge	Pipeline	Rail
Distance (Miles, one-way) - Default	5082	500	750	800
Distance (Miles, one-way)	0	2200	1985	2485
Share of Fuel Type Used:				
Diesel	0	0	0.45	1
Residual Oil	1	1	NA	NA
Natural Gas	0	0	0.55	NA
Electricity	NA	NA	NA	NA
Energy Intensity: Btu/ton-mile				
Origin to Destination	27.4	402.9	252.6	370.0
Back-Haul	24.3	307.1		
Total Energy consumption: Btu/MMBtu-	1.5	20.7	7.4	10.8
Total Emissions: grams/MMBtu-mile fuel transported				
VOC (incl. VOC from bulk term	0.000	0.001	0.000	0.001
CO	0.000	0.005	0.002	0.002
CH4 (incl. fugitive)	0.000	0.000	0.000	0.000
N2O	0.000	0.000	0.000	0.000
CO2	0.127	1.751	0.496	0.837
GHG	0.129	1.773	0.506	0.851

Table 2.8: Percentage of Fuel Transported by a Given Mode

Mode	Percent
Ocean tanker	0.0%
Barge	0.0%
Pipeline	0.0%
Rail	100.0%

Notes:
The shares here are for each mode traveled by the distance assumed above.
The total percentage of all modes may exceed 100% for some feedstocks or fuels because more than one transportation legs may be involved for transporting the feedst

Table 2.9: Feed losses: Btu/MMBtu fuel transported

Feed loss	62

3 Calculations

		Value	Unit
3.1	Crude transport energy consumption	26846.8	Btu/MMBtu
3.2	Crude transport GHG emissions	2115.8	gCO2eq/MMBtu

Bitumen Extraction and Upgrading - Railcar Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

1 Results

	User	Units	User reference	Default reference
1.1 Total energy consumption	0.25	MJ/MJ		
1.1.1 Total energy consumption primary extraction	0.25	MJ/MJ		
1.1.1.1 Direct energy consumption primary extraction	0.20	MJ/MJ		
1.1.1.2 Indirect energy consumption primary extraction	0.05	MJ/MJ		
1.1.2 Total energy consumption upgrading	0.00	MJ/MJ		
1.1.2.1 Direct energy consumption upgrading	0.00	MJ/MJ		
1.1.2.2 Indirect energy consumption upgrading	0.00	MJ/MJ		
1.2 Total GHG emissions (excluding VFF)	16.34	gCO_2eq/MJ		
1.2.1 Primary extraction total GHG emissions - combustion emissions	16.34	gCO_2eq/MJ		
1.2.1.1 Direct emissions primary extraction	11.30	gCO_2eq/MJ		
1.2.1.2 Indirect emissions primary extraction	5.04	gCO_2eq/MJ		
1.2.2 Primary extraction - VFF emissions	3.30	gCO_2eq/MJ		
1.2.2 Upgrading - combustion emissions	0.00	gCO_2eq/MJ		
1.2.2.1 Direct emissions upgrading	0.00	gCO_2eq/MJ		
1.2.2.2 Indirect emissions upgrading	0.00	gCO_2eq/MJ		

2 Input assumptions and data

	User	Default	Units	User reference	Default reference
2.1 Crude or SCO name	WCSB	Generic			
2.2 Crude bitumen properties					
2.2.1 Crude bitumen API gravity	8	8	deg. API		GHGenius 4.0c
2.2.2 Crude bitumen specific gravity	1.01	1.01	sg		
2.2.3 Crude bitumen heating value	6.10	6.1	MMBtu/bbl (LHV)		
2.3 Synthetic crude oil (SCO) properties					
2.3.1 SCO API gravity	32	32	deg. API		www.crudemonitor.ca
2.3.2 SCO specific gravity	0.87	0.87	sg		
2.3.3 SCO heating value	5.47	5.47	MMBtu/bbl (LHV)		
2.4 Diluent properties					
2.4.1 Diluent API gravity	59.37	59.37	deg. API		
2.4.2 Diluent specific gravity	0.74	0.74	sg		
2.4.3 Diluent heating value	5.39	5.39	MMBtu/bbl (LHV)		
2.5 Oil production rate (choose bitumen output or SCO below)	830000	1500	STB/d		
	5.06E+09	8.20E+06	Mbtu LHV/d		
	5.34E+09	8.65E+06	MJ/d		
2.6 Project pathway choices					
2.6.1 Upgrading or blending					
2.6.1.1 Hydrocarbon upgraded - Produce SCO	0	1	NA		
2.6.1.2 Hydrocarbon not upgraded - Produce bitumen for dilution	1	0	NA		
Check:	OK	OK			
2.6.2 Primary extraction methodology					

Bitumen Extraction and Upgrading - Railcar Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

2.6.2.1	Mining integrated		0	1	NA	
2.6.2.2	Mining non-integrated		0	0	NA	
2.6.2.3	In situ - Non-thermal production (primary)		0	0	NA	
2.6.2.4	In situ - Steam assisted gravity drainage (SAGD)		1	0	NA	
2.6.2.5	In situ - Cyclic steam stimulation (CSS)		0	0	NA	
		Check:	OK	OK		
2.7	In situ steam oil ratio (SOR)					
2.7.1	Steam assisted gravity drainage (SAGD) SOR		3.0	3.0	bbl steam/bbl bitumen	GHGenius 4.0c, (S&T
2.7.2	Cyclic steam stimulation (CSS) SOR		3.9	3.9	bbl steam/bbl bitumen	GHGenius 4.0c, (S&T
2.8	Diluent blending					
2.8.1	Volume fraction of dilbit as diluent		0.15	0.25	bbl diluent/bbl dilbit	
2.8.2	Volume fraction of dilbit as bitumen		0.85	0.75	bbl bitumen/bbl dilbit	
2.8.3	Dilbit heating value		5.99	5.92	MMBtu/bbl dilbit	
2.9	Fuels imported for extraction (or recorded as net imports)					
2.9.1	Diesel fuel		0	0		
2.9.2	Natural gas		1	1		
2.9.3	Electricity		1	1		
2.9.4	Coke		0	0		
2.9.5	Still Gas		0	0		
2.9.6	Diluent		1	1		
2.10	Fuels imported for upgrading (or recorded as net imports)					
2.9.1	Diesel fuel		0	0		
2.9.2	Natural gas		1	1		
2.9.3	Electricity		1	1		
2.9.4	Coke		0	0		
2.9.5	Still Gas		0	0		
2.11	Associated gas composition	N_2	2.00	2.00	mol%	
		CO_2	6.00	6.00	mol%	
		C_1	84.00	84.00	mol%	
		C_2	4.00	4.00	mol%	
		C_3	2.00	2.00	mol%	
		C_4+	1.00	1.00	mol%	
		H_2S	1.00	1.00	mol%	
2.12	Land use impact inputs					
2.12.1	Crude ecosystem carbon richness					
1=	Low carbon richness (semi-arid grasslands)		0	0	NA	Yeh et al. (2010)
2=	Moderate carbon richness (mixed)		0	1	NA	Yeh et al. (2010)
3=	High carbon richness (forested)		1	0	NA	Yeh et al. (2010)
		Check:	OK	OK		
2.12.2	Field development intensity					
1=	Low intensity development and low oxidation		0	0	NA	Yeh et al. (2010)
2=	Moderate intensity development and moderate oxidation		0	1	NA	Yeh et al. (2010)
3=	High intensity development and high oxidation		1	0	NA	Yeh et al. (2010)
		Check:	OK	OK		

Bitumen Extraction and Upgrading - Railcar Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Emissions code: 9 11

3 Calculations

			User	Units
3.1	Direct energy consumption			
3.1.1	Energy consumed primary extraction (in situ and mining, includes mining for integrated mining & upgrading)			
3.1.1.1	Diesel fuel		0.00	MMBtu/bbl dilbit
3.1.1.2	Natural gas	1.196273	1.20	MMBtu/bbl dilbit
3.1.1.3	Electricity		0.03	MMBtu/bbl dilbit
3.1.1.4	Coke		0.00	MMBtu/bbl dilbit
3.1.1.5	Still Gas		0.00	MMBtu/bbl dilbit
3.1.2	Energy consumed upgrading (includes upgrading for integrated mining & upgrading)			
3.1.2.1	Diesel fuel		0.00	MMBtu/bbl dilbit
3.1.2.2	Natural gas		0.00	MMBtu/bbl dilbit
3.1.2.3	Electricity		0.00	MMBtu/bbl dilbit
3.1.2.4	Coke		0.00	MMBtu/bbl dilbit
3.1.2.5	Still Gas		0.00	MMBtu/bbl dilbit
3.1.3	Direct energy consumed (net, extraction + upgrading)			
3.1.3.1	Diesel fuel		0.000	MMBtu/bbl dilbit
3.1.3.2	Natural gas		1.196	MMBtu/bbl dilbit
3.1.3.3	Electricity		0.030	MMBtu/bbl dilbit
3.1.3.4	Coke		0.000	MMBtu/bbl dilbit
3.1.3.5	Still Gas		0.000	MMBtu/bbl dilbit
3.2	Fugitive emissions, venting, and flaring			
3.2.1	Gas released via fugitive emissions and direct venting		36.3	scf/bbl dilbit
3.2.1.1	Fugitive emissions GWP weighted		15129	gCO2eq./bbl dilbit
3.2.2	Gas consumed in flares		77	scf/bbl dilbit
3.2.1.1	Gas flared - Combustion products GWP weighted		4159.3	gCO2eq./bbl dilbit
3.2.1.2	Gas flared - Slippage products GWP weighted		1594.4	gCO2eq./bbl dilbit
3.3	Energy imports (net imports for computing upstream fuel cycle emissions)			
3.3.1	Energy imports primary extraction (in situ and mining, includes mining for integrated mining & upgrading)			
3.3.1.1	Diesel fuel		0.00	MMBtu/bbl dilbit
3.3.1.2	Natural gas		1.20	MMBtu/bbl dilbit
3.3.1.3	Electricity		0.03	MMBtu/bbl dilbit
3.3.1.4	Coke		0.00	MMBtu/bbl dilbit
3.3.1.5	Still Gas		0.00	MMBtu/bbl dilbit
3.3.1.6	Diluent		0.81	MMBtu/bbl dilbit
3.3.2	Energy imports upgrading (includes upgrading for integrated mining & upgrading)			
3.3.2.1	Diesel fuel		0.00	MMBtu/bbl dilbit
3.3.2.2	Natural gas		0.00	MMBtu/bbl dilbit
3.3.2.3	Electricity		0.00	MMBtu/bbl dilbit
3.3.2.4	Coke		0.00	MMBtu/bbl dilbit
3.3.2.5	Still Gas		0.00	MMBtu/bbl dilbit
3.4	Total energy consumption			
3.4.1	Direct energy consumption			
3.4.1.1	Primary extraction		1.23	MMBtu/bbl dilbit

Bitumen Extraction and Upgrading - Railcar Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

3.4.1.2 Upgrading	0.00	MMBtu/bbl dilbit	
3.4.2 Indirect energy consumption			
3.4.2.1 Primary extraction	0.29	MMBtu/bbl dilbit	
3.4.2.2 Upgrading	0.00	MMBtu/bbl dilbit	
3.5 Land use GHGs			
3.5.1 Soil carbon emissions	3.5	g/MJ dilbit	Yeh et al. (2010)
3.5.2 Biomass carbon emissions	2.9	g/MJ dilbit	Yeh et al. (2010)
3.5.3 Foregone sequestration emissions	0.0	g/MJ dilbit	Yeh et al. (2010)
3.5.4 Total land use emissions	6.5	g/MJ dilbit	
3.6 Total GHG emissions			
3.5.1 Direct GHG emissions			
3.5.1.1 Primary extraction	71496	g/bbl dilbit	
3.5.1.2 Upgrading	0	g/bbl dilbit	
3.5.2 Indirect GHG emissions			
3.5.2.1 Primary extraction	31864	g/bbl dilbit	
3.5.2.2 Upgrading	0	g/bbl dilbit	

4 Data tables

Table 4.1: Energy demand for primary bitumen extraction
Volumetric and mass units

	Primary	SAGD	CSS	Mining	
Diesel fuel	6	0	0	35	L diesel/m3 bitumen
Natural gas	130	255	270	73	m3/m3 bitumen
Electricity	115	65	55	-70	kWh/m3 bitumen
Coke	0	0	0	0	kg/m3 bitumen
Still Gas	0	0	0	0	m3/m3 bitumen

Source: GHGenius v 4.03a, 'Crude Production' D293-G301 for different selected production techniques.
Data quality for primary production is poor. O'Connor models primary production between heavy oil production and SAGD based on a consultancy study (GHGenius oil production update, March 2011, p. 41)

Table 4.2: Energy demand for primary bitumen extraction
Volumetric and mass units

	Primary	SAGD	CSS	Mining	
Diesel fuel	0.030	0.000	0.000	0.189	MMBtu LHV/bbl bitumen
Natural gas	0.717	1.407	1.490	0.405	MMBtu LHV/bbl bitumen
Electricity	0.062	0.035	0.030	-0.038	MMBtu LHV/bbl bitumen
Coke	0.000	0.000	0.000	0.000	MMBtu LHV/bbl bitumen
Still Gas	0.000	0.000	0.000	0.000	MMBtu LHV/bbl bitumen

Bitumen Extraction and Upgrading - Railcar Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Table 4.3: Energy demand for upgrading
Energy units (MJ LHV/tonne SCO)

	Stand-alone upgrader	Integrated mining & upgrading	Units
Diesel fuel		565	MJ LHV/tonne SCO
Natural gas	4736	4612	MJ LHV/tonne SCO
Electricity	217	-100	MJ LHV/tonne SCO
Coke	1278	1573	MJ LHV/tonne SCO
Still Gas	4208	3115	MJ LHV/tonne SCO

Source: GHGenius v 4.03a, 'Crude Production' L292-N301, converted from reported GHGenius HHVs to LHVs using GHGenius HHV/LHV ratios from "Fuel Char" sheet column R
Notes: GHGenius assumes a 1:1 mass ratio for bitumen to SCO production for stand-alone operations.
The density of SCO assumed in GHGenius is not clear, so we assume 32 API as in Suncor Synthetic A synthetic crude oil
We assume that fugitives are same as above for mining operations, but that integrated upgrading adds the remainder as flare emissions.

Table 4.4: Energy demand for upgrading
Energy units (MMBtu/bbl SCO)

	Stand-alone upgrader	Integrated mining & upgrading	Units
Diesel fuel	0.000	0.074	MMBtu LHV/bbl SCO
Natural gas	0.618	0.601	MMBtu LHV/bbl SCO
Electricity	0.028	-0.013	MMBtu LHV/bbl SCO
Coke	0.167	0.205	MMBtu LHV/bbl SCO
Still Gas	0.549	0.406	MMBtu LHV/bbl SCO

Table 4.5: Steam injection rates for in situ projects

	SOR	Units
CSS	3.9	bbl steam/bbl bitumen
SAGD	3.0	bbl steam/bbl bitumen

GHGenius 4.0c, (S&T)^2, March 2011 Update of oil production and refining in GHGenius, p. 40-44

Table 4.6: Volumetric gain upon conversion to SCO

	Gain	Units

Bitumen Extraction and Upgrading - Railcar Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Integrated upgrading gain	0.9	m^3 SCO/m^3 bitumen
Stand alone upgrading gain	1.2	m^3 SCO/m^3 bitumen

Notes:
GHGenius assumes a 1:1 mass ratio for bitumen to SCO production for stand-alone operations.
GHGenius assumes a 1.25:1 mass ratio for bitumen to SCO production for integrated upgraders (coking based rather than via hydrogen addition as in stand-alone Scotford upgrader)

Table 4.7: Diluent composition

Diluent type	Density	API gravity	C1-C3	C4	C5	C6	C7	C8	C9	C10	C11	C12	C12+	C	H	Mass C	Mass H	Mass Frac C
CRW-675	727.20	62.90	0.00	0.05	0.30	0.21	0.16	0.09	0.05	0.03	0.02	0.01	0.07	6.90	15.79	82.75	15.79	0.84
CPC 475 PetroCanada condensate (	757.20	55.20	0.00	0.00	0.00	0.07	0.35	0.34	0.17	0.05	0.01	0.00	0.00	7.83	17.66	93.94	17.66	0.84
CPR 0822 Peace condensate (2006)	739.60	59.60	0.01	0.07	0.22	0.21	0.17	0.10	0.05	0.03	0.03	0.02	0.08	7.18	16.36	86.18	16.36	0.84

Assumed species	C3H8	C4H10	C5H12	C6H14	C7H16	C8H18	C9H20	C10H22	C11H24	C12H26	C14H30
C	3	4	5	6	7	8	9	10	11	12	14
H	8	10	12	14	16	18	20	22	24	26	30

Notes:
Source: Analysis of Blending Data used in Condensate EQ model. Prepared for Canadian Association of Petroleum Producers (CAPP) by Advantage Insight Group Inc. January 2007
C5 contains normal and iso-pentane, as well as cyclopentane
C6 contains Benzene and methylcyclopentane as well as cyclohexane
C7 contains heptanes as well as toluene and methylcyclohexane
C8 contains octanes plus xylenes
C9 contains nonanes as well as 1,2,4 trimethybenzene
For simplicity, assume parafinic HCs
Dulong formula is used to approximate the heating value of the condensate/diluent

Table 4.8: Other dilbit properties

Property	Value	Unit
Dilbit blending energy	0.00	MMBtu/bbl
Diluent embodied energy	0.11	MMBtu/MMBtu diluent
Diluent embodied emissions	8175.25	g/MMBtu diluent

Notes:
Assume blending dilbit has negligible energy cost
Assume diluent has identical embodied energy and emissions as natural gas

Table 4.9: Flaring emissions from bitumen extraction operations

	Primary	SAGD	CSS	Mining	
Flaring emissions	0.00009	0.00009	0.00009	0.00009	MMscf/bbl
Flaring emissions	90.0	90.0	90.0	90.0	scf/bbl

Values for flaring emissions from NOAA satellite observations for average Canadian crude production, for consistency with other flaring datasets and due to its verifiable data source.

Bitumen Extraction and Upgrading - Railcar Scenario

Mass Frac H	HHV		LHV		HHV		LHV	
0.16	22196.06	Btu/lb	20797.04	Btu LHV/lb	5.66	MMBtu/bbl	5.30	MMBtu/bbl
0.16	22099.58	Btu/lb	20718.33	Btu LHV/lb	5.86	MMBtu/bbl	5.50	MMBtu/bbl
0.16	22163.89	Btu/lb	20770.79	Btu LHV/lb	5.74	MMBtu/bbl	5.38	MMBtu/bbl

Bitumen Extraction and Upgrading - Railcar Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Table 4.10: Fugitive emissions from bitumen extraction operations

	Primary	SAGD	CSS	Mining	
Fugitive emissions	7500	7500	7500	5480	L/tonne bitumen
Fugitive emissions	42.7	42.7	42.7	31.2	scf/bbl

All mining emissions are fugitives, as these are mine face fugitive methane and methane from tailings ponds. See GHGenius 2011 report: Update of oil production and refining data in GHGenius, Tables 4-18 and 4-19.

All in situ emissions are fugitives from gathering and processing systems (batteries). See GHGenius 2011 report: Update of oil production and refining data in GHGenius, Figure 4-16 for 2009.

PIPELINE SCENARIO

User Inputs and Summary Results - Pipeline Scenario

1 Summary results

Model error check: **OK**

Table 1.1: Summary GHG emissions

GHG emissions [gCO2eq/MJ]					
	WCSB				
Exploration	0.00				
Drilling	6.47				
Production	9.48				
Processing	0.00				
Upgrading	0.00				
Maintenance	0.00				
Waste	0.00				
VFF	2.77				
Diluent	0.00				
Misc.	0.50				
Transport	0.95				
Offsite emissions	6.22				
Net lifecycle emis	26.39				

Notes: Copy highlighted column and paste 'as numbers' to generate a record

Figure 1.1: Summary GHG emissions

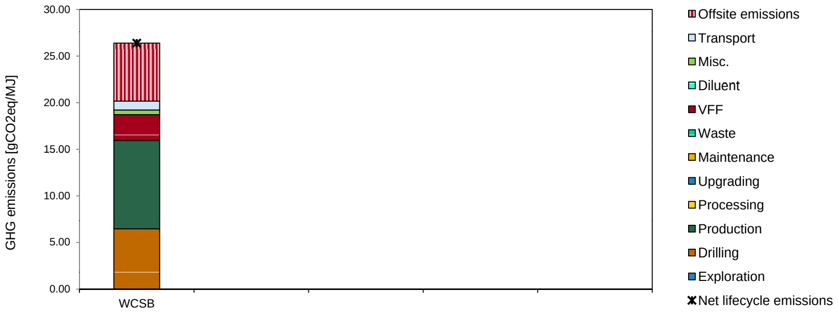
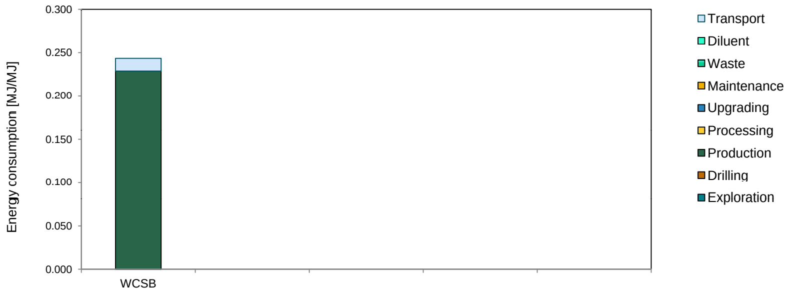


Table 1.2: Summary energy consumption

Energy consumption [MJ/MJ]					
	WCSB				
Exploration	0.00				
Drilling	0.00				
Production	0.23				
Processing	0.00				
Upgrading	0.00				
Maintenance	0.00				
Waste	0.00				
Diluent	0.00				
Transport	0.01				
Total	0.243				

Notes: Copy highlighted column and paste 'as numbers' to generate a record

Figure 1.2: Summary energy consumption



2 Petroleum resource

2.1 Conventional		0	1	NA
2.2 Bitumen		1	0	NA
	Check:	OK	OK	

3 User inputs - Conventional

Enter primary input parameters and choices	User	Default	Unit	Notes

3.1 Production methods

Note: Enter "1" where applicable and "0" where not applicable

User Inputs and Summary Results - Pipeline Scenario

3.1.1	Downhole pump		1	1	NA	
3.1.2	Water reinjection		1	1	NA	If water flooding applies then "0"
3.1.3	Gas reinjection		1	1	NA	If gas flooding applies then "0"
3.1.4	Water flooding		0	0	NA	This is used for injecting amounts of water larger than the ar
3.1.5	Gas lifting	OK	0	0	NA	This is used for gas lifting
3.1.6	Gas flooding		0	0	NA	This is used for injecting a different type of gas (e.g. N2) or a
3.1.7	Steam flooding		0	0	NA	This is used for injecting steam
3.2	Field properties					
3.2.1	Field location (Country)	OK	Canada	Generic	NA	
3.2.2	Field name		WCSB	Generic	NA	
3.2.3	Field age		40	35	yr	
3.2.4	Field depth		550	7240	ft	
3.2.5	Oil production volume		830000	1500	bbl/d	
3.2.6	Number of producing wells		8300	4536	[-]	
3.2.7	Number of water injecting wells		8300	4416	[-]	
3.2.8	Well diameter		7.0	2.8	in	
3.2.9	Productivity index		3.0	3.0	bbl/psi-d	
3.2.10	Average reservoir pressure		1557	118	psi	Downhole pump on
3.3	Fluid properties					
3.3.1	API gravity of produced crude		8	30	deg. API	
3.3.2	Associated gas composition					
		N_2	2.00	2.0	mol%	Composition on dry basis
		CO_2	6.00	6.0	mol%	
		C_1	84.00	84.0	mol%	
		C_2	4.00	4.0	mol%	
		C_3	2.00	2.0	mol%	
		C_4+	1.00	1.0	mol%	
		H_2S	1.00	1.0	mol%	
		Sum				
3.4	Production practices					
Notes: Enter "NA" where not applicable						
3.4.1	Gas-to-oil ratio (GOR)		908	227	scf/bbl oil	In the case of gas lift, the gas oil ratio should include produc
3.4.2	Water-to-oil ratio (WOR)		4.3	5.5	bbl water/bbl oil	
3.4.3	Water injection ratio	OK	5.3	5.3	bbl water/bbl oil	
3.4.4	Gas lifting injection ratio	OK	1500	1500	scf/bbl liquid	Gas lifting injection (does not include gas reinjected into the
3.4.5	Gas flooding injection ratio	OK	1362	1362	scf/bbl oil	
3.4.6	Steam-to-oil ratio (SOR)	OK	3.0	3.0	bbl steam/bbl oil	
3.4.7	Fraction of required electricity generated onsite		0.00	0.00	[-]	
3.4.8	Fraction of remaining gas reinjected	OK	0.00	0.00	[-]	1.0 if gas flooding applies (Note: Do not enter NA at all times
3.4.9	Fraction of water produced reinjected		1.00	1.00	[-]	1.0 if water flooding applies (Note: Do not enter NA at all tim
3.4.10	Fraction of steam generation via co-generation		0.00	0.00	[-]	
3.5	Processing practices					
3.5.1	Heater/treater (1= Applicable; 0= Not applicable)		1	1	NA	
3.5.2	Stabilizer column (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.3	Application of AGR unit (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.4	Application of gas dehydration unit (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.5	Application of demethanizer unit (1= Applicable; 0 = Not applicable)		1	1	NA	
3.5.6	Ratio of flaring to oil production		82	82	scf/bbl	Default calculated based on satellite data from NOAA
3.5.7	Ratio of venting to oil production		0.0	0.0	scf/bbl	This is the ratio of venting used as a disposal mechanism (d
3.5.8	Volume fraction of diluent in diluted crude	OK	0.000	0.000	[-]	Default is the minimum indicated by the model inputs
3.6	Land use impacts					

User Inputs and Summary Results - Pipeline Scenario

3.6.1 Crude ecosystem carbon richness				
3.6.1.1 Low carbon richness (semi-arid grasslands)	0	0	NA	
3.6.1.2 Moderate carbon richness (mixed)	0	1	NA	
3.6.1.3 High carbon richness (forested)	1	0	NA	
3.6.2 Field development intensity				
3.6.2.1 Low intensity development and low oxidation	0	0	NA	
3.6.2.2 Moderate intensity development and moderate oxidation	0	1	NA	
3.6.2.3 High intensity development and high oxidation	1	0	NA	
3.7 Non-integrated upgrader (1= Applicable; 0= Not applicable)	0	0	NA	
3.8 Crude oil transport				
3.8.1 Fraction of oil transported by each mode				The total fraction of all modes may exceed 1.0 because mor
3.8.1.1 Ocean tanker	0	1	[-]	
3.8.1.2 Barge	0	0	[-]	
3.8.1.3 Pipeline	1	1	[-]	
3.8.1.4 Rail	0	0	[-]	
3.8.2 Transport distance (one way)				
3.8.2.1 Ocean tanker	0	5082	Miles	
3.8.2.2 Barge	2200	500	Miles	
3.8.2.3 Pipeline	1985	750	Miles	
3.8.2.4 Rail	2485	800	Miles	
3.8.3 Ocean tanker size, if applicable	250000	250000	Tons	
3.9 Small sources emissions	0.5	0.5	gCO_2 eq/MJ	Assumption to account for numerous small sources not inclu

Status

3.10 Overall error check **OK** **Error check** For specific error checks see section 7 below

4 User inputs - Bitumen

Notes:
Change user inputs in Bitumen Extraction & Upgrading sheet.
Change crude production method in Drilling & Development sheet (section 2.1.3).

5 Summary results - Conventional

These results are derived from calculations in following sheets

	Value	Unit	Notes
5.1 Exploration			
5.1.1 Total energy consumption	0.000	MJ/MJ	Exploration energy use is not included in the current version of the model
5.1.2 Total GHG emissions	0.00	gCO_2eq/MJ	Exploration emissions are not included in the current version of the model
5.1.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
5.1.2.2 VFF	0.00	gCO_2eq/MJ	
5.2 Drilling & Development			
5.2.1 Total energy consumption	0.000	MJ/MJ	
5.2.2 Total GHG emissions	0.00	gCO_2eq/MJ	
5.2.2.1 Combustion/land use	0.00	gCO_2eq/MJ	

User Inputs and Summary Results - Pipeline Scenario

5.2.2.2 VFF	0.00	gCO$_2$eq/MJ	
5.3 Crude production & extraction			
5.3.1 Total energy consumption	0.000	MJ/MJ	
5.3.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	MJ of crude output
5.3.2.1 Combustion/land use	0.00	gCO$_2$eq/MJ	
5.3.2.2 VFF	0.00	gCO$_2$eq/MJ	
5.4 Surface processing			
5.4.1 Total energy consumption	0.000	MJ/MJ	
5.4.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	MJ of crude output
5.4.2.1 Combustion/land use	0.00	gCO$_2$eq/MJ	
5.4.2.2 VFF	0.00	gCO$_2$eq/MJ	
5.5 Maintenance			
5.5.1 Total energy consumption	0.000	MJ/MJ	
5.5.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	MJ of crude output
5.5.2.1 Combustion/land use	0.00	gCO$_2$eq/MJ	
5.5.2.2 VFF	0.00	gCO$_2$eq/MJ	
5.6 Waste disposal			
5.6.1 Total energy consumption	0.000	MJ/MJ	Waste disposal energy use is not included in the current version of the model
5.6.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	Waste disposal emissions are not included in the current version of the model
5.6.2.1 Combustion/land use	0.00	gCO$_2$eq/MJ	
5.6.2.2 VFF	0.00	gCO$_2$eq/MJ	
5.7 Diluent			
5.7.1 Total energy consumption	0.000	MJ/MJ	
5.7.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	
5.8 Non-integrated upgrader			
5.8.1 Total energy consumption	0.000	MJ/MJ	
5.8.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	MJ of SCO
5.9 Crude transport			
5.9.1 Total energy consumption	0.000	MJ/MJ	
5.9.2 Total GHG emissions	0.00	gCO$_2$eq/MJ	MJ of crude transported
5.9.3 Loss factor	0.0000	NA	Calculated from crude oil losses
5.10 Other small sources	0.00	gCO$_2$eq/MJ	See sheet "Model Organization" for list of all sources not explicitly modeled in OPGEE. These sources are included her
5.11 Offsite emissions credit/debit	0.00	gCO$_2$eq/MJ	Credits (negative emissions) from fuels export + debts (positive emissions) from fuels import
5.12 Lifecycle energy consumption	0.00	MJ/MJ	
5.13 Lifecycle GHG emissions	0.00	gCO$_2$eq/MJ	MJ of crude at refinery gate

6 Summary result - Bitumen

These results are derived from calculations in Bitumen Extraction & Upgrading sheet.

	Value	Unit	Notes
6.1 Exploration			
6.1.1 Total energy consumption	0.000	MJ/MJ	Exploration energy use is not included in the current version of the model

User Inputs and Summary Results - Pipeline Scenario

6.1.2 Total GHG emissions	0.00	gCO_2eq/MJ	Exploration emissions are not included in the current version of the model
6.1.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
6.1.2.2 VFF	0.00	gCO_2eq/MJ	
6.2 Drilling & Development			
6.2.1 Total energy consumption	0.000	MJ/MJ	Energy use and emissions from mine preparation are included in bitumen extraction figures
6.2.2 Total GHG emissions	6.47	gCO_2eq/MJ	
6.2.2.1 Combustion/land use	6.47	gCO_2eq/MJ	
6.2.2.2 VFF	0.00	gCO_2eq/MJ	
6.3 Bitumen extraction			
6.3.1 Total energy consumption	0.229	MJ/MJ	
6.3.2 Total GHG emissions	12.24	gCO_2eq/MJ	MJ of bitumen output
6.3.2.1 Combustion/land use	9.48	gCO_2eq/MJ	
6.3.2.2 VFF	2.77	gCO_2eq/MJ	
6.4 Upgrading			
6.4.1 Total energy consumption	0.000	MJ/MJ	
6.4.2 Total GHG emissions	0.00	gCO_2eq/MJ	MJ of bitumen output
6.4.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
6.4.2.2 VFF	0.00	gCO_2eq/MJ	
6.5 Maintenance			
6.5.1 Total energy consumption	0.000	MJ/MJ	
6.5.2 Total GHG emissions	0.00	gCO_2eq/MJ	MJ of bitumen output
6.5.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
6.5.2.2 VFF	0.00	gCO_2eq/MJ	
6.6 Waste disposal			
6.6.1 Total energy consumption	0.000	MJ/MJ	Waste disposal energy use is not included in the current version of the model
6.6.2 Total GHG emissions	0.00	gCO_2eq/MJ	Waste disposal emissions are not included in the current version of the model
6.6.2.1 Combustion/land use	0.00	gCO_2eq/MJ	
6.6.2.2 VFF	0.00	gCO_2eq/MJ	
6.7 Crude transport			
6.7.1 Total energy consumption	0.015	MJ/MJ	
6.7.2 Total GHG emissions	0.95	gCO_2eq/MJ	MJ of crude transported
6.7.3 Loss factor	1.0001	NA	Calculated from crude oil losses
6.8 Other small sources	0.50	gCO_2eq/MJ	
6.9 Offsite emissions credit/debit	6.22		Credits (negative emissions) from fuels export + debts (positive emissions) from fuels import
6.10 Lifecycle energy consumption	0.24	MJ/MJ	
6.11 Lifecycle GHG emissions	26.39	gCO_2eq/MJ	MJ of crude at refinery gate

7 Error check

	Sheet	Cell	Status	Notes
7.1 Specific error checks				

User Inputs and Summary Results - Pipeline Scenario

7.1.1	Production methods	User Inputs & Results	I61	OK
7.1.2	Water injection ratio	User Inputs & Results	I92	OK
7.1.3	Gas injection volume	User Inputs & Results	I93	OK
7.1.4	N2 injection ratio	User Inputs & Results	I94	OK
7.1.5	Steam-to-oil ratio (SOR)	User Inputs & Results	I95	OK
7.1.6	Field location	User Inputs & Results	I66	OK
7.1.7	Volume fraction of diluent	User Inputs & Results	I109	OK
7.1.8	Crude production method	Drilling & Development	M43	OK
7.1.9	Crude ecosystem carbon richness	Drilling & Development	M48	OK
7.1.10	Field development intensity	Drilling & Development	M53	OK
7.1.11	Gas composition	Production & Extraction	M45	OK
7.1.12	Fraction of gas to reinjection	Production & Extraction	L49	OK
7.1.13	Fraction of water to reinjection	Production & Extraction	L56	OK
7.1.14	Number of producing wells	Production & Extraction	L64	OK
7.1.15	Productivity index	Production & Extraction	L66	OK
7.1.16	Ratio of specific heats	Production & Extraction	L203	OK
7.1.17	NGL use	Surface Processing	L122	OK
7.1.18	Stage 1 water treatment	Surface Processing	L131	OK
7.1.19	Stage 2 water treatment	Surface Processing	L134	OK
7.1.20	Stage 3 water treatment	Surface Processing	L143	OK
7.1.21	Stage 4 water treatment	Surface Processing	L151	OK
7.1.22	Lift gas volume	Gas Balance	AP19	OK
7.1.23	Remaining gas volume	Gas Balance	AP28	OK
7.1.24	Steam injection	Steam Injection	M65	OK
7.1.25	Offsite electricity fuel mix	Electricity	C48 & C63	OK
7.1.26	Remainig gas > Fuel gas demand	Gas Balance	AR26	OK

Drilling and Development - Pipeline Scenario

Estimation of GHG emissions from drilling and field development

1 Drilling combustion emissions

	User	Default	Units	User reference	Default reference
1.1 Field drilling and development properties					
1.1.1 Crude location	Canada	USA			
1.1.2 Crude name	WCSB	Generic			
1.1.3 Field depth	550	7240	ft	Imperial Aspen Project	
1.1.4 API gravity	8	30		Typical Oil Sand API	
1.1.5 Crude oil heating value	6.10	5.51	MMBtu LHV/bbl		
1.2. Drilling energy consumption during field development					
1.2.1 Energy intensity of drilling	2	1	NA		
1= Low intensity drilling					
2= High intensity drilling					
1.2.2 Energy intensity of drilling	103.9	104.5	MMBtu/1000 ft		
1.2.3 Energy intensity per well	57.2	756.7	MMBtu/well		
1.3. Per-well lifetime productivity					
1.3.1 Expected lifetime well productivity	547500	130000	bbl/well	100 bpd, 15 years	
1.3.1.1. Expected lifetime energy production	3340254	716898	MMBtu/well		
1.4. Fractional energy consumption per well drilled	0.0000	0.0011	MMBtu/MMBtu		

2 Land use impacts

	User	Default	Units	User reference	Default reference
2.1 Crude development properties					
2.1.1 Crude location	Canada	Generic			
2.1.2 Crude name	WCSB	Generic			
2.1.3 Crude production method					
2.1.3.1 Conventional, in situ production via wellbore	1	1	NA		
2.1.3.2 Mining-based production	0	0	NA		
Check:	OK	OK			
2.1.4 Crude ecosystem carbon richness					
2.1.4.1 Low carbon richness (semi-arid grasslands)	0	0	NA		Yeh et al. (2010)
2.1.4.2 Moderate carbon richness (mixed)	0	1	NA		Yeh et al. (2010)
2.1.4.3 High carbon richness (forested)	1	0	NA	Boreal Forest	Yeh et al. (2010)
Check:	OK	OK			
2.1.5 Field development intensity					
2.1.5.1 Low intensity development and low oxidation	0	0	NA		Yeh et al. (2010)
2.1.5.2 Moderate intensity development and moderate oxidation	0	1	NA		Yeh et al. (2010)
2.1.5.3 High intensity development and high oxidation	1	0	NA		Yeh et al. (2010)
Check:	OK	OK			
2.1.6 Timeframe of land use analysis (1 = 30 years, 2 = 150 years)	1	1			
Emissions code:	9	5			

Drilling and Development - Pipeline Scenario

Estimation of GHG emissions from drilling and field development

2.2 Source-specific land use emissions				
2.2.1 Soil carbon emissions	3.51	0.57	gCO_2eq/MJ	Yeh et al. (2010)
2.2.2 Biomass carbon emissions	2.94	0.68	gCO_2eq/MJ	Yeh et al. (2010)
2.2.3 Foregone sequestration emissions	0.02	0.01	gCO_2eq/MJ	Yeh et al. (2010)
2.3 Total land use emissions	6.5	1.3	gCO_2eq/MJ	

Crude Transport - Pipeline Scenario

Calculation of GHG emissions from crude oil transportation to refinery
Based on CA-GREET model

1 Results

		Value	Units
1.1	Total energy consumption	0.01	MJ/MJ
1.2	Total GHG emissions	0.95	gCO_2eq/MJ

2 Input assumptions and data

Table 2.1: Cargo Payload By Transportation Mode and by Product Fuel Type: Tons

Fuel Transported	Crude Oil
Ocean Tanker	250000
Barge	22500

Table 2.2: Horsepower Requirements for Ocean Tanker and Barges: Calculated with Cargo Capacity (unit is in HP)

	Crude Oil
Ocean Tank	34320.0
Barge	5600.0

Table 2.3: Energy Consumption for Ocean Tanker and Barge

	Ocean Tanker	Barge
Average Speed (Miles/Hour)	18.5	5.0
Trip from Product Origin to Destination		
Load Factor	80.0%	80.0%
Energy Consumption: Btu/hp-hr	4620	10119
Trip from Product Destination Back to Origin		
Load Factor	70.0%	60.0%
Energy Consumption: Btu/hp-hr	4691	10284

Notes: The load factor is the percentage of installed horsepower that is used for the trip

Table 2.4: Energy Intensity of Rail Transportation: Btu/ton-mile

Trip	Intensity
Trip from Product Origin to Destination	370
Trip from Product Destination Back to O	370

Table 2.5: Energy Intensity of Pipeline Transportation: Btu/ton-mile

	Turbine	Reciprocating Engine: Current	Reciprocating Engine: Future
Crude Pipeli	240	270	260

Table 2.6: Share of Power Generation Technologies for Pipeline Compression Stations

	Turbine	Reciprocating Engine: Current	Reciprocating Engine: Future
Crude Pipeli	55.0%	36.0%	9.0%

Crude Transport - Pipeline Scenario

Calculation of GHG emissions from crude oil transportation to refinery
Based on CA-GREET model

Table 2.7: Energy Consumption and Emissions of Feedstock Transportation

Feedstock	Crude Oil			
Transportation Mode	Tanker	Barge	Pipeline	Rail
Distance (Miles, one-way) - Default	5082	500	750	800
Distance (Miles, one-way)	0	2200	1985	2485
Share of Fuel Type Used:				
Diesel	0	0	0.45	1
Residual Oil	1	1	NA	NA
Natural Gas	0	0	0.55	NA
Electricity	NA	NA	NA	NA
Energy Intensity: Btu/ton-mile				
Origin to Destination	27.4	402.9	252.6	370.0
Back-Haul	24.3	307.1		
Total Energy consumption: Btu/MMBtu-	1.5	20.7	7.4	10.8
Total Emissions: grams/MMBtu-mile fuel transported				
VOC (incl. VOC from bulk term	0.000	0.001	0.000	0.001
CO	0.000	0.005	0.002	0.002
CH4 (incl. fugitive)	0.000	0.000	0.000	0.000
N2O	0.000	0.000	0.000	0.000
CO2	0.127	1.751	0.496	0.837
GHG	0.129	1.773	0.506	0.851

Table 2.8: Percentage of Fuel Transported by a Given Mode

Mode	Percent
Ocean tanker	0.0%
Barge	0.0%
Pipeline	100.0%
Rail	0.0%

Notes:
The shares here are for each mode traveled by the distance assumed above.
The total percentage of all modes may exceed 100% for some feedstocks or fuels because more than one transportation legs may be involved for transporting the feedstocks.

Table 2.9: Feed losses: Btu/MMBtu fuel transported

Feed loss	62

3 Calculations

	Value	Unit
3.1 Crude transport energy consumption	14668.7	Btu/MMBtu
3.2 Crude transport GHG emissions	1004.9	gCO2eq/MMBtu

Bitumen Extraction and Upgrading - Pipeline Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

1 Results

	User	Units	User reference	Default reference
1.1 Total energy consumption	0.23	MJ/MJ		
1.1.1 Total energy consumption primary extraction	0.23	MJ/MJ		
1.1.1.1 Direct energy consumption primary extraction	0.17	MJ/MJ		
1.1.1.2 Indirect energy consumption primary extraction	0.06	MJ/MJ		
1.1.2 Total energy consumption upgrading	0.00	MJ/MJ		
1.1.2.1 Direct energy consumption upgrading	0.00	MJ/MJ		
1.1.2.2 Indirect energy consumption upgrading	0.00	MJ/MJ		
1.2 Total GHG emissions (excluding VFF)	15.70	gCO_2eq/MJ		
1.2.1 Primary extraction total GHG emissions - combustion emissions	15.70	gCO_2eq/MJ		
1.2.1.1 Direct emissions primary extraction	9.48	gCO_2eq/MJ		
1.2.1.2 Indirect emissions primary extraction	6.22	gCO_2eq/MJ		
1.2.2 Primary extraction - VFF emissions	2.77	gCO_2eq/MJ		
1.2.2 Upgrading - combustion emissions	0.00	gCO_2eq/MJ		
1.2.2.1 Direct emissions upgrading	0.00	gCO_2eq/MJ		
1.2.2.2 Indirect emissions upgrading	0.00	gCO_2eq/MJ		

2 Input assumptions and data

	User	Default	Units	User reference	Default reference
2.1 Crude or SCO name	WCSB	Generic			
2.2 Crude bitumen properties					
2.2.1 Crude bitumen API gravity	8	8	deg. API		GHGenius 4.0c
2.2.2 Crude bitumen specific gravity	1.01	1.01	sg		
2.2.3 Crude bitumen heating value	6.10	6.1	MMBtu/bbl (LHV)		
2.3 Synthetic crude oil (SCO) properties					
2.3.1 SCO API gravity	32	32	deg. API		www.crudemonitor.ca
2.3.2 SCO specific gravity	0.87	0.87	sg		
2.3.3 SCO heating value	5.47	5.47	MMBtu/bbl (LHV)		
2.4 Diluent properties					
2.4.1 Diluent API gravity	59.37	59.37	deg. API		
2.4.2 Diluent specific gravity	0.74	0.74	sg		
2.4.3 Diluent heating value	5.39	5.39	MMBtu/bbl (LHV)		
2.5 Oil production rate (choose bitumen output or SCO below)	830000	1500	STB/d		
	5.06E+09	8.20E+06	Mbtu LHV/d		
	5.34E+09	8.65E+06	MJ/d		
2.6 Project pathway choices					
2.6.1 Upgrading or blending					
2.6.1.1 Hydrocarbon upgraded - Produce SCO	0	1	NA		
2.6.1.2 Hydrocarbon not upgraded - Produce bitumen for dilution	1	0	NA		
Check:	OK	OK			
2.6.2 Primary extraction methodology					

Bitumen Extraction and Upgrading - Pipeline Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

2.6.2.1	Mining integrated		0	1	NA	
2.6.2.2	Mining non-integrated		0	0	NA	
2.6.2.3	In situ - Non-thermal production (primary)		0	0	NA	
2.6.2.4	In situ - Steam assisted gravity drainage (SAGD)		1	0	NA	
2.6.2.5	In situ - Cyclic steam stimulation (CSS)		0	0	NA	
		Check:	OK	OK		
2.7	In situ steam oil ratio (SOR)					
2.7.1	Steam assisted gravity drainage (SAGD) SOR		3.0	3.0	bbl steam/bbl bitumen	GHGenius 4.0c, (S&T
2.7.2	Cyclic steam stimulation (CSS) SOR		3.9	3.9	bbl steam/bbl bitumen	GHGenius 4.0c, (S&T
2.8	Diluent blending					
2.8.1	Volume fraction of dilbit as diluent		0.30	0.25	bbl diluent/bbl dilbit	
2.8.2	Volume fraction of dilbit as bitumen		0.70	0.75	bbl bitumen/bbl dilbit	
2.8.3	Dilbit heating value		5.89	5.92	MMBtu/bbl dilbit	
2.9	Fuels imported for extraction (or recorded as net imports)					
2.9.1	Diesel fuel		0	0		
2.9.2	Natural gas		1	1		
2.9.3	Electricity		1	1		
2.9.4	Coke		0	0		
2.9.5	Still Gas		0	0		
2.9.6	Diluent		1	1		
2.10	Fuels imported for upgrading (or recorded as net imports)					
2.9.1	Diesel fuel		0	0		
2.9.2	Natural gas		1	1		
2.9.3	Electricity		1	1		
2.9.4	Coke		0	0		
2.9.5	Still Gas		0	0		
2.11	Associated gas composition	N_2	2.00	2.00	mol%	
		CO_2	6.00	6.00	mol%	
		C_1	84.00	84.00	mol%	
		C_2	4.00	4.00	mol%	
		C_3	2.00	2.00	mol%	
		C_4+	1.00	1.00	mol%	
		H_2S	1.00	1.00	mol%	
2.12	Land use impact inputs					
2.12.1	Crude ecosystem carbon richness					
1=	Low carbon richness (semi-arid grasslands)		0	0	NA	Yeh et al. (2010)
2=	Moderate carbon richness (mixed)		0	1	NA	Yeh et al. (2010)
3=	High carbon richness (forested)		1	0	NA	Yeh et al. (2010)
		Check:	OK	OK		
2.12.2	Field development intensity					
1=	Low intensity development and low oxidation		0	0	NA	Yeh et al. (2010)
2=	Moderate intensity development and moderate oxidation		0	1	NA	Yeh et al. (2010)
3=	High intensity development and high oxidation		1	0	NA	Yeh et al. (2010)
		Check:	OK	OK		

Bitumen Extraction and Upgrading - Pipeline Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Emissions code: 9 11

3 Calculations

			User	Units
3.1	Direct energy consumption			
3.1.1	Energy consumed primary extraction (in situ and mining, includes mining for integrated mining & upgrading)			
3.1.1.1	Diesel fuel		0.00	MMBtu/bbl dilbit
3.1.1.2	Natural gas	0.985166	0.99	MMBtu/bbl dilbit
3.1.1.3	Electricity		0.02	MMBtu/bbl dilbit
3.1.1.4	Coke		0.00	MMBtu/bbl dilbit
3.1.1.5	Still Gas		0.00	MMBtu/bbl dilbit
3.1.2	Energy consumed upgrading (includes upgrading for integrated mining & upgrading)			
3.1.2.1	Diesel fuel		0.00	MMBtu/bbl dilbit
3.1.2.2	Natural gas		0.00	MMBtu/bbl dilbit
3.1.2.3	Electricity		0.00	MMBtu/bbl dilbit
3.1.2.4	Coke		0.00	MMBtu/bbl dilbit
3.1.2.5	Still Gas		0.00	MMBtu/bbl dilbit
3.1.3	Direct energy consumed (net, extraction + upgrading)			
3.1.3.1	Diesel fuel		0.000	MMBtu/bbl dilbit
3.1.3.2	Natural gas		0.985	MMBtu/bbl dilbit
3.1.3.3	Electricity		0.025	MMBtu/bbl dilbit
3.1.3.4	Coke		0.000	MMBtu/bbl dilbit
3.1.3.5	Still Gas		0.000	MMBtu/bbl dilbit
3.2	Fugitive emissions, venting, and flaring			
3.2.1	Gas released via fugitive emissions and direct venting		29.9	scf/bbl dilbit
3.2.1.1	Fugitive emissions GWP weighted		12459	gCO2eq./bbl dilbit
3.2.2	Gas consumed in flares		63	scf/bbl dilbit
3.2.1.1	Gas flared - Combustion products GWP weighted		3425.3	gCO2eq./bbl dilbit
3.2.1.2	Gas flared - Slippage products GWP weighted		1313.1	gCO2eq./bbl dilbit
3.3	Energy imports (net imports for computing upstream fuel cycle emissions)			
3.3.1	Energy imports primary extraction (in situ and mining, includes mining for integrated mining & upgrading)			
3.3.1.1	Diesel fuel		0.00	MMBtu/bbl dilbit
3.3.1.2	Natural gas		0.99	MMBtu/bbl dilbit
3.3.1.3	Electricity		0.02	MMBtu/bbl dilbit
3.3.1.4	Coke		0.00	MMBtu/bbl dilbit
3.3.1.5	Still Gas		0.00	MMBtu/bbl dilbit
3.3.1.6	Diluent		1.62	MMBtu/bbl dilbit
3.3.2	Energy imports upgrading (includes upgrading for integrated mining & upgrading)			
3.3.2.1	Diesel fuel		0.00	MMBtu/bbl dilbit
3.3.2.2	Natural gas		0.00	MMBtu/bbl dilbit
3.3.2.3	Electricity		0.00	MMBtu/bbl dilbit
3.3.2.4	Coke		0.00	MMBtu/bbl dilbit
3.3.2.5	Still Gas		0.00	MMBtu/bbl dilbit
3.4	Total energy consumption			
3.4.1	Direct energy consumption			
3.4.1.1	Primary extraction		1.01	MMBtu/bbl dilbit

Bitumen Extraction and Upgrading - Pipeline Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

3.4.1.2 Upgrading 0.00 MMBtu/bbl dilbit

3.4.2 Indirect energy consumption

3.4.2.1 Primary extraction 0.34 MMBtu/bbl dilbit
3.4.2.2 Upgrading 0.00 MMBtu/bbl dilbit

3.5 Land use GHGs

3.5.1 Soil carbon emissions	3.5	g/MJ dilbit	Yeh et al. (2010)
3.5.2 Biomass carbon emissions	2.9	g/MJ dilbit	Yeh et al. (2010)
3.5.3 Foregone sequestration emissions	0.0	g/MJ dilbit	Yeh et al. (2010)
3.5.4 Total land use emissions	6.5	g/MJ dilbit	

3.6 Total GHG emissions

3.5.1 Direct GHG emissions

3.5.1.1 Primary extraction 58879 g/bbl dilbit
3.5.1.2 Upgrading 0 g/bbl dilbit

3.5.2 Indirect GHG emissions

3.5.2.1 Primary extraction 38640 g/bbl dilbit
3.5.2.2 Upgrading 0 g/bbl dilbit

4 Data tables

Table 4.1: Energy demand for primary bitumen extraction
Volumetric and mass units

	Primary	SAGD	CSS	Mining	
Diesel fuel	6	0	0	35	L diesel/m3 bitumen
Natural gas	130	255	270	73	m3/m3 bitumen
Electricity	115	65	55	-70	kWh/m3 bitumen
Coke	0	0	0	0	kg/m3 bitumen
Still Gas	0	0	0	0	m3/m3 bitumen

Source: GHGenius v 4.03a, 'Crude Production' D293-G301 for different selected production techniques.
Data quality for primary production is poor. O'Connor models primary production between heavy oil production and SAGD based on a consultancy study (GHGenius oil production update, March 2011, p. 41)

Table 4.2: Energy demand for primary bitumen extraction
Volumetric and mass units

	Primary	SAGD	CSS	Mining	
Diesel fuel	0.030	0.000	0.000	0.189	MMBtu LHV/bbl bitumen
Natural gas	0.717	1.407	1.490	0.405	MMBtu LHV/bbl bitumen
Electricity	0.062	0.035	0.030	-0.038	MMBtu LHV/bbl bitumen
Coke	0.000	0.000	0.000	0.000	MMBtu LHV/bbl bitumen
Still Gas	0.000	0.000	0.000	0.000	MMBtu LHV/bbl bitumen

Bitumen Extraction and Upgrading - Pipeline Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Table 4.3: Energy demand for upgrading
Energy units (MJ LHV/tonne SCO)

	Stand-alone upgrader	Integrated mining & upgrading	Units
Diesel fuel		565	MJ LHV/tonne SCO
Natural gas	4736	4612	MJ LHV/tonne SCO
Electricity	217	-100	MJ LHV/tonne SCO
Coke	1278	1573	MJ LHV/tonne SCO
Still Gas	4208	3115	MJ LHV/tonne SCO

Source: GHGenius v 4.03a, 'Crude Production' L292-N301, converted from reported GHGenius HHVs to LHVs using GHGenius HHV/LHV ratios from "Fuel Char" sheet column R
Notes: GHGenius assumes a 1:1 mass ratio for bitumen to SCO production for stand-alone operations.
The density of SCO assumed in GHGenius is not clear, so we assume 32 API as in Suncor Synthetic A synthetic crude oil
We assume that fugitives are same as above for mining operations, but that integrated upgrading adds the remainder as flare emissions.

Table 4.4: Energy demand for upgrading
Energy units (MMBtu/bbl SCO)

	Stand-alone upgrader	Integrated mining & upgrading	Units
Diesel fuel	0.000	0.074	MMBtu LHV/bbl SCO
Natural gas	0.618	0.601	MMBtu LHV/bbl SCO
Electricity	0.028	-0.013	MMBtu LHV/bbl SCO
Coke	0.167	0.205	MMBtu LHV/bbl SCO
Still Gas	0.549	0.406	MMBtu LHV/bbl SCO

Table 4.5: Steam injection rates for in situ projects

	SOR	Units
CSS	3.9	bbl steam/bbl bitumen
SAGD	3.0	bbl steam/bbl bitumen

GHGenius 4.0c, (S&T)^2, March 2011 Update of oil production and refining in GHGenius, p. 40-44

Table 4.6: Volumetric gain upon conversion to SCO

	Gain	Units

Bitumen Extraction and Upgrading - Pipeline Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Integrated upgrading gain	0.9	m^3 SCO/m^3 bitumen
Stand alone upgrading gain	1.2	m^3 SCO/m^3 bitumen

Notes:

GHGenius assumes a 1:1 mass ratio for bitumen to SCO production for stand-alone operations.

GHGenius assumes a 1.25:1 mass ratio for bitumen to SCO production for integrated upgraders (coking based rather than via hydrogen addition as in stand-alone Scotford upgrader)

Table 4.7: Diluent composition

Diluent type	Density	API gravity	C1-C3	C4	C5	C6	C7	C8	C9	C10	C11	C12	C12+	C	H	Mass C	Mass H	Mass Frac C
CRW-675	727.20	62.90	0.00	0.05	0.30	0.21	0.16	0.09	0.05	0.03	0.02	0.01	0.07	6.90	15.79	82.75	15.79	0.84
CPC 475 PetroCanada condensate (	757.20	55.20	0.00	0.00	0.00	0.07	0.35	0.34	0.17	0.05	0.01	0.00	0.00	7.83	17.66	93.94	17.66	0.84
CPR 0822 Peace condensate (2006)	739.60	59.60	0.01	0.07	0.22	0.21	0.17	0.10	0.05	0.03	0.03	0.02	0.08	7.18	16.36	86.18	16.36	0.84

Assumed species	C_3H_8	C_4H_{10}	C_5H_{12}	C_6H_{14}	C_7H_{16}	C_8H_{18}	C_9H_{20}	$C_{10}H_{22}$	$C_{11}H_{24}$	$C_{12}H_{26}$	$C_{14}H_{30}$
C	3	4	5	6	7	8	9	10	11	12	14
H	8	10	12	14	16	18	20	22	24	26	30

Notes:

Source: Analysis of Blending Data used in Condensate EQ model. Prepared for Canadian Association of Petroleum Producers (CAPP) by Advantage Insight Group Inc. January 2007

C5 contains normal and iso-pentane, as well as cyclopentane

C6 contains Benzene and methylcyclopentane as well as cyclohexane

C7 contains heptanes as well as toluene and methylcyclohexane

C8 contains octanes plus xylenes

C9 contains nonanes as well as 1,2,4 trimethybenzene

For simplicity, assume parafinic HCs

Dulong formula is used to approximate the heating value of the condensate/diluent

Table 4.8: Other dilbit properties

Property	Value	Unit
Dilbit blending energy	0.00	MMBtu/bbl
Diluent embodied energy	0.11	MMBtu/MMBtu diluent
Diluent embodied emissions	8175.25	g/MMBtu diluent

Notes:

Assume blending dilbit has negligible energy cost

Assume diluent has identical embodied energy and emissions as natural gas

Table 4.9: Flaring emissions from bitumen extraction operations

	Primary	SAGD	CSS	Mining	
Flaring emissions	0.00009	0.00009	0.00009	0.00009	MMscf/bbl
Flaring emissions	90.0	90.0	90.0	90.0	scf/bbl

Values for flaring emissions from NOAA satellite observations for average Canadian crude production, for consistency with other flaring datasets and due to its verifiable data source.

Table 4.10: Fugitive emissions from bitumen extraction operations

	Primary	SAGD	CSS	Mining	
Fugitive emissions	7500	7500	7500	5480	L/tonne bitumen

Bitumen Extraction and Upgrading - Pipeline Scenario

Mass Frac H	HHV		LHV		HHV		LHV	
0.16	22196.06	Btu/lb	20797.04	Btu LHV/lb	5.66	MMBtu/bbl	5.30	MMBtu/bbl
0.16	22099.58	Btu/lb	20718.33	Btu LHV/lb	5.86	MMBtu/bbl	5.50	MMBtu/bbl
0.16	22163.89	Btu/lb	20770.79	Btu LHV/lb	5.74	MMBtu/bbl	5.38	MMBtu/bbl

Bitumen Extraction and Upgrading - Pipeline Scenario

This worksheet contains a simple model of emissions from bitumen extraction and upgrading

Fugitive emissions	42.7	42.7	42.7	31.2	scf/bbl

All mining emissions are fugitives, as these are mine face fugitive methane and methane from tailings ponds. See GHGenius 2011 report: Update of oil production and refining data in GHGenius, Tables 4-18 and 4-19.

All in situ emissions are fugitives from gathering and processing systems (batteries). See GHGenius 2011 report: Update of oil production and refining data in GHGenius, Figure 4-16 for 2009.

Environmental Engineering

Capstone Report Approval Form

Master of Science in Environmental Engineering – MSEV

Milwaukee School of Engineering

This report, entitled “Energy Policy Review: How Effective Was Denying the Keystone XL Pipeline Presidential Permit in Reducing Green House Gas Emissions from Canadian Oil Sands Crude?,” submitted by the student Marie M. Venné, has been approved by the following committee:

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